State of California
Department of Water Resources

Determination of Revenue Requirements

For the Period

January 1, 2003 Through December 31, 2003

With Reexamination and Redetermination For the Period

January 17, 2001 Through December 31, 2002

Submitted To
The California Public Utilities Commission
Pursuant To
Sections 80110 and 80134 of the California Water Code

August 16, 2002

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A. THE DETERMINATION

Authority

Pursuant to Sections 80110 and 80134 of the California Water Code and the Rate Agreement between the State of California Department of Water Resources (the "Department") and the California Public Utilities Commission (the "Commission") dated as of March 8, 2002 (the "Rate Agreement"), the Department, by means of this Determination of Revenue Requirements (this "Determination"), hereby advises and notifies the Commission of (1) the result of the Department's reexamination of its revenue requirement for the period January 17, 2001, through and including December 31, 2002 (the "First Revenue Requirement Period"), and (2) its revenue requirement for the period January 1, 2003, through and including December 31, 2003 (the "Second Revenue Requirement Period," and collectively with the First Revenue Requirement Period, the "Revenue Requirement Periods"). The Department has made these revenue requirement and "just and reasonable" determinations in accordance with the Rate Agreement, California Water Code, Division 27 (the "Act") and California Code of Regulations, Division 23, Chapter 4, Sections 510–517 (the "Regulations").

The notice of proposed determination dated June 14, 2002, was sent to the persons or entities that provided comments or requested notice of the prior determination dated November 5, 2001, and any other persons or entities requesting notice of this current revenue requirement determination (collectively, "interested persons"). The original deadline for submitting comments was July 5, 2002. The Department held a workshop at 12:30 p.m. on June 19, 2002, at the Auditorium of the Employment Development Department, 722 Capitol Mall, Sacramento, which focused on a review of the Department's proposed revenue requirement determination (the "Proposed Determination"). The Department sponsored a series of four daily conference calls on July 1 through 3, 2002 and July 8, 2002, allowing parties to ask questions and receive immediate responses pertaining to the Proposed Determination. On each of July 10, 2002, July 26, 2002, August 9, 2002 and August 13, 2002, the Department distributed a notice of significant additional material to interested persons as provided by the Regulations. Concurrent with the distribution of the significant additional material, the comment period for the Proposed Determination and the significant additional material was extended and comments were due on July 16, 2002, August 5, 2002 and August 14, 2002, respectively. All comments provided, whether in response to the Proposed Determination or any of the "significant additional material", have been reviewed by the Department and an assessment made as to whether there was a material impact on the Revenue Requirements. To the extent changes in the Revenue Requirements were necessary or appropriate they have been incorporated.

The Department assumed responsibility for the purchase of the net short energy requirements of the retail customers of the investor-owned utilities (the "IOUs") on January 17, 2001 when the IOUs were no longer creditworthy and could not purchase energy in the market. On February 1, 2001, Assembly Bill 1 from the First Extraordinary Session of 2001 was enacted into law, containing, among other things, the Act. The Act authorized the Department to purchase the net short energy requirements of the customers. The "net short" is equal to total IOU customer energy requirements minus supply from resources owned, operated or contracted by the IOUs. The Department has, in accordance with the Act, procured the net short requirements of the IOUs using a combination of long-term energy contracts and short-term energy purchases. The amount of energy required to be purchased on a short-term basis, after the application of energy from long-term contracts entered into by the Department, is referred to as the "residual net short". The costs of the Department's purchases to meet the net short requirements of the customers of the IOUs are to be recovered from payments made by the customers and collected by the IOUs on behalf of the Department. The terms and conditions for the recovery of the Department's costs from customers are set forth in the Act, the Regulations and the Rate Agreement. Among other things, the Rate Agreement establishes the foundation for a "Bond Charge" (as that term is defined in the Rate Agreement) that is designed to recover the Department's costs associated with its intended bond financing activity ("Bond Related Costs") and a "Power Charge" (as that term is defined in the Rate Agreement) that is designed to recover "Department Costs", or the Department's "Retail Revenue Requirements" (as those terms are defined in the Rate Agreement), including power supply-related costs. Subject to the conditions described in the Rate Agreement and other Commission Decisions, Bond Charges and certain charges designed to recover Department Costs may also be imposed on the customers of Electric Service Providers (as that term is defined in the Rate Agreement). The implementation of such charges world, of course, affect the amounts described in this Determination as needed to be recovered from Bond Charges and Power Charges imposed on customers of the Department and the IOUs. The Department has funded its purchases of energy from January 17, 2001, to date from a combination of revenues collected by the IOUs on behalf of the Department, advances from the State General Fund, and the proceeds of an interim financing of $4.3 billion in June 2001 (the "Interim Loan"). Approximately $7 billion of power costs paid by the Department to meet the net short energy needs of the Customers have not yet been reflected in retail electric rates. These costs will be reimbursed and certain debt service reserves and operating reserves will be created from the proceeds of revenue bonds in the projected amount of approximately $11.8 billion. Repayment of the bonds will be made from the Bond Charge established in the Rate Agreement, as described in more detail herein.

The Department has previously provided to the Commission the Department's November 5, 2001 determination of revenue requirements and, consented to certain modifications to such revenue requirements in connection with the implementation thereof by the Commission. A section within this determination re-examines the Department's costs implemented in rates in the Commission's Decisions 02-02-052 and 02-03-003, as modified by Decision 02-03-062 (collectively, the "2001-2002 Rate Decision"). While the Act provides, in effect, that the Department's authority to procure the residual net short requirements of the utilities' customers terminates as of December 31, 2002, the Act permits the Department to manage its then-existing portfolio of longer-term contracts through their respective terms. Thus, a principal assumption in the determination of revenue requirements over the period January 1, 2003, through December 31, 2003, is that the Department will no longer be responsible for the acquisition of the IOUs' residual net short energy requirements and only the costs associated with the Department's long-term contracts and their administration are included. A later section of this determination provides preliminary estimates of the costs associated with the Department's continued involvement in the procurement of the residual net short requirements of the IOUs, if the Department's continued involvement were to be necessary and legally authorized.

As per the requirements of Section 80134 of the California Water Code and the Rate Agreement, this Determination contains information on the amounts required to be recovered in the Revenue Requirement Periods. In addition, a reconciliation of the Department's revenue requirements through the first quarter of 2002 relative to the amounts provided in the 2001-2002 Rate Decision[1] is presented. This reconciliation, together with revised projections for the remainder of 2002 and related Department determinations, constitutes the re-examination and redetermination of the Department's revenue requirement for the First Revenue Requirement Period.

For the Second Revenue Requirement Period, this determination contains information on the following[2]: (a) the beginning balance of funds on deposit in the Electric Power Fund (the "Fund"), including the amounts on deposit in each account and sub-account of the Fund, (b) the amounts necessary to pay or provide for the principal of, premium, if any, and interest on all bonds and all other Bond Related Costs as and when the same shall become due and the aggregate amount of bond charges projected to be required to be collected for such purpose, and (c) the amount of the Department's Retail Revenue Requirements.

Determination of Revenue Requirements

Pursuant to the Act, the Rate Agreement and the Regulations, the Department hereby determines, on the basis of the materials presented and referred to by this Determination (including the materials referred to in Appendix 3), that its cash basis revenue requirement for the Second Revenue Requirement Period, to be implemented by charges calculated and imposed by the Commission, is $5.788 billion, consisting of $1.140 billion in Bond Related Costs and $4.648 billion in Department Costs.

Table A-1 shows a summary of the Department's revenue requirements and accounts associated with its projected Department Costs ("Power Charge Accounts") for the Second Revenue Requirement Period. A similar summary of the Department's revenue requirements and accounts associated with its Bond Related Costs ("Bond Charge Accounts") are presented in Table A-2. Definitions of key accounts and subaccounts are presented within each table.

[1] Appendix A, Table 1 of the California Public Utilities Commission, Decision 02-02-052 in Application 00-11-038 et al., dated February 21, 2002.

[2] Where appropriate, the Department has provided information in this determination on a quarterly basis for the revenue requirement period. In other instances, particularly where information might be considered market-sensitive, the Department has provided information on an annual basis. .

TABLE A-1
SUMMARY OF THE DEPARTMENT'S REVENUE REQUIREMENTS AND ACCOUNTS: POWER CHARGE ACCOUNTS

Line	Description	Amounts for Revenue Requirement Period (Millions of Dollars)
1	*Balance in Power Charge Accounts*	
2	Operating Account	$1,228
3	Priority Contract Account	–
4	Operating Reserve Account	777
5	**Total Beginning Balance in Power Charge Accounts**	**$2,005**
6	*Power Charge Accounts Operating Revenues*	
7	Power Charge Revenues	$4,648
8	Other Power Sales	129
9	Interest Earnings on Fund Balances	59
10	**Total Power Charge Accounts Operating Revenues**	**$4,836**
11	*Power Charge Accounts Operating Expenses*	
12	Administrative and General Expenses	$28
13	Total Power Costs	4,120
14	Ancillary Services	170
15	**Total Power Charge Account Operating Expenses**	**$4,319**
16	Net Operating Revenues	$517
17	Net Transfers from/(to) Bond Charge Accounts	–
18	Total Net Revenues	$517
19	**Ending Aggregate Balance in Power Charge Accounts**	$2,523

2003 Target Minimum Power Charge Account Balances	Target (Millions of Dollars)
Operating Account: This target minimum balance is designed to cover volatility in operating cash flows. The $1 billion target balance will be in place until the Department is no longer responsible for the Residual Net Short, at which point the target minimum balance will be reduced to reflect maximum intra-month volatility in the account as measured by the maximum difference in operating revenues and expenses.	$1,000
Operating Reserve Account: Used to cover deficiencies in the Operating Account. It is sized as the greater of the rolling seven-month difference between operating revenues and expenses as calculated under "stress" operating conditions and 18 percent of projected 2003 operating expenses. In this case, the account is sized at 18 percent of projected 2003 operating expenses.	$777

TABLE A-2
SUMMARY OF THE DEPARTMENT'S REVENUE REQUIREMENTS AND ACCOUNTS: BOND CHARGE ACCOUNTS

Line	Description	Amounts for Revenue Requirement Period (Millions of Dollars)
1	*Beginning Balance in Bond Charge Accounts*	
2	Bond Charge Collection Account	$56
3	Bond Charge Payment Account	269
4	Debt Service Reserve Account	974
5	**Total Beginning Balance in Bond Charge Accounts**	**$1,298**
6	*Bond Charge Account Revenues*	
7	Bond Charge Revenues from Utilities	$1,140
8	Revenue Bonds Net Proceeds	–
9	Interest Earnings on Fund Balances	27
10	**Total Bond Charge Account Revenues**	**$1,167**
11	*Bond Charge Account Expenses*	
12	Debt Service on Bonds	$632
13	Other Bond Charge Account Expenses	–
14	**Total Bond Charge Account Expenses**	**$632**
15	Net Bond Charge Revenues	$535
16	Net Transfers from/(to) Power Charge Accounts	–
17	Total Net Revenues	$535
19	**Ending Aggregate Balance in Bond Charge Accounts**	**$1,834**

2003 Target Bond Charge Account Balances	Target (Millions of Dollars)
Bond Charge Collection Account: An amount equal to one month's required deposit to the Bond Charge Payment Account for projected debt service	$53–82
Bond Charge Payment Account: An amount equal to the debt service accrued and unpaid through the end of the third next succeeding calendar month.	$158–247
Debt Service Reserve Account: An amount equal to the maximum annual debt service on the Bonds.	$974

The Department hereby determines that for the First Revenue Requirement Period, its total customer-related revenue requirement, i.e., total funds required by the Department to cover its operating expenses and debt service related costs, is $9.092 billion. Relative to the $9.045 billion customer revenue requirement adopted by the Commission in its February 2002 order adopting Department's revenue requirements for the First Revenue Requirement Period, the Department currently estimates an undercollection of about $46 million or 0.5 percent for the First Revenue Requirement Period.[3]

Table C-1 in Section C of this Determination shows, among other things, a summary of the Department's revenue requirements associated with its power charges for the First Revenue Requirement Period.

Determination That Revenue Requirements Are Just and Reasonable

Pursuant to the Act and the Regulations, the Department hereby determines, on the basis of the materials presented and referred to by this Determination (including the testimony presented in Section G of this Determination and materials referred to in Appendix 3), that the revenue requirements determined hereby are just and reasonable within the meaning of the Act and the Regulations.

Future Adjustment of Revenue Requirements

The Department notes that because the California energy market and its participants continue to be subject to significant change, the Department may need to revise its revenue requirements for the Revenue Requirement Periods. Factors that may influence the Department's revenue requirements for the Revenue Requirement Periods include, but are not limited to:

(1) Decisions adopted by the Commission in its deliberations regarding direct access for customers that opt for generation service from an Electric Service Provider.

(2) Changes to the Department's responsibility for providing the net short and residual net short requirements of the customers of IOUs.

(3) Financing-related factors, including, but not limited to, the timing of the issuance of the Power Supply Revenue Bonds (the "Bonds") and the final structure and terms of the Bonds.

(4) Changes to the California electricity marketplace. The California Independent System Operator ("CAISO") is undergoing a process of redesign for the operation of the transmission system and the movement of bulk (wholesale) power in California. The redesign, called Market Design 2002 ("MD02"), is being carried out in response to orders issued by the Federal Energy Regulatory Commission ("FERC"). The FERC Order on Clarification and Rehearing of December 19, 2001, directed the CAISO to file its revised congestion management proposal and a plan for implementation of a day-ahead market. In addition, the CAISO is responding to the various market monitoring and mitigation orders by the FERC (described in Appendix 1 of this Determination). To the extent that

[3] In determining the amount of the revenue requirements for the Second Revenue Requirement Period the Department has assumed that the Department charges imposed by the 2001–2002 Rate Decision remain in effect for the entire First Revenue Requirement Period.

changes to the California electricity marketplace may arise on account of these ongoing initiatives, there may be a material change in the Department's revenue requirements in both the First and Second Revenue Requirement Periods. In the event that such changes may materialize, the Department will, first, inform the Commission of such changes and, second, revise its revenue requirement projections accordingly.

These factors are discussed in more detail within the section titled "Key Uncertainties in the Revenue Requirement Determinations."

B. BACKGROUND

Section 80110 of the Water Code provides in part that "The Department shall be entitled to recover, as a revenue requirement, amounts and at the times necessary to enable it to comply with Section 80134, and shall advise the Commission as the Department determines to be appropriate." Section 80110 also provides that any "just and reasonable" review of its revenue requirements shall be conducted and determined by the Department. In addition, Section 80134 of the Water Code provides that:

"(a) The Department shall, and in any obligation entered into pursuant to this division may covenant to, at least annually, and more frequently as required, establish and revise revenue requirements sufficient, together with any moneys on deposit in the fund, to provide all of the following:

"(1) The amounts necessary to pay the principal of and premium, if any, and interest on all bonds as and when the same shall become due.

"(2) The amounts necessary to pay for power purchased by it and to deliver it to purchasers, including the cost of electric power and transmission, scheduling, and other related expenses incurred by the department, or to make payments under any other contracts, agreements, or obligation entered into by it pursuant hereto, in the amounts and at the times the same shall become due.

"(3) Reserves in such amount as may be determined by the Department from time to time to be necessary or desirable.

"(4) The pooled money investment rate on funds advanced for electric power purchases prior to the receipt of payment for those purchases by the purchasing entity.

"(5) Repayment to the General Fund of appropriations made to the fund pursuant hereto or hereafter for purposes of this division, appropriations made to the Department of Water Resources Electric Power Fund, and General Fund moneys expended by the department pursuant to the Governor's Emergency Proclamation dated January 17, 2001.

"(6) The administrative costs of the Department incurred in administering this division.

"(b) The Department shall notify the Commission of its revenue requirement pursuant to Section 80110."

Pursuant to the requirement of Sections 80110 and 80134 of the California Water Code, the Department submitted an initial estimated determination of revenue requirements to the Commission on May 2, 2001, covering the period from January 17, 2001 through and including May 31, 2002. Following this initial submittal, the Department provided the Commission with updates dated July 23, 2001, August 7, 2001, and November 5, 2001, all of which covered the period January 17, 2001, through and including December 31, 2002. In its determination of revenue requirements dated November 5, 2001, the Department estimated a total revenue requirement of $10.003 billion for the period January 17, 2001 through and including December 31, 2002. On February 21, 2002, the Department advised the Commission that the costs needed to be recovered by the 2001-2002 Rate Decision could be reduced by $958 million.[4] The Commission, in its 2001-2002 Rate Decision, implemented cost recovery of the Department's revenue requirements, adjusted by that amount. A summary of the Commission's implementation of the Department's revenue requirements is provided in Section C, Table C-1.

Concurrent with its action on the 2001-2002 Rate Decision, the Commission issued a decision adopting a Rate Agreement between the Commission and the Department establishing the procedures to be followed to calculate and adjust the charges to the Customers for Department power, such that the Department is assured of recovering its Retail Revenue Requirements.[5] The purpose of the Rate Agreement is to facilitate the issuance of bonds that enable the repayment of the General Fund and Interim Loan, and the funding of appropriate reserves for the bonds.[6]

The Rate Agreement between the Commission and the Department establishes two streams of revenue for the Department. One stream of revenue is generated from "Bond Charges" imposed for the purpose of providing sufficient funds to pay "Bond Related Costs." Bond Charges are applied based on the aggregate amount of electric power sold to each customer by the Department and the applicable IOU, and, to the extent provided by final non-appealable Commission orders, Electric Service Providers. Bond Related Costs include Bond debt service, credit enhancement and liquidity facilities charges, and costs relating to other financial instruments and servicing arrangements entered into in connection with the Bonds. The Bond Charges will be imposed upon customers whether or not the Department is selling power to those customers. The Rate Agreement requires the Commission to impose Bond Charges that are sufficient, together with amounts on deposit in the Bond Charge Collection Account, to pay all Bond Related Costs as they come due.

The second stream of revenue is generated from "Power Charges" imposed on Customers who buy power from the Department, and is designed to pay for

[4] The two major components of the change were (a) a reduction of $609 million due to the Commission's draft order in the Utility Retained Generation (URG) proceeding considering requiring the IOUs to reimburse the Department for certain CAISO-related costs and (b) a reduction of $349 million on account of a revision to the assumption regarding the timing of the bond issuance to repay the Department's Interim Loan (as well as the General Fund).

[5] California Public Utilities Commission, Decision 02-02-051, "Opinion adopting a Rate Agreement between the Commission and the California Department of Water Resources," adopted February 21, 2002, as modified by Decision 02-03-063, adopted March 21, 2002.

[6] To fund the power supply program, the Department has relied on revenues collected by the IOUs on behalf of the Department, the General Fund Loans, the proceeds of an interim loan of $4.3 billion entered into on June 26, 2001 with several financial institutions, and revenues collected from the Customers to satisfy its revenue requirements associated with the power supply program. The Department plans to issue bonds late in the 3rd quarter or early in the fourth quarter of 2002, the proceeds of which will be used, in part, to reimburse the State's General Fund for the General Fund Loans as well as repay the Interim Loan.

"Department Costs," including the costs that the Department incurs to procure and deliver power. The Rate Agreement requires the Commission to impose Power Charges that are sufficient to provide moneys in the amounts and at the times necessary to satisfy the Retail Revenue Requirements specified by the Department[7]. Revenues received from Power Charges and Bond Charges, as well as the payment of expenditures and obligations from such revenues, are held in and accounted for in the fund established by the Department under the Act for the procurement of power supply resources (the "Electric Power Fund").

To enable the Commission to set Bond Charges and Power Charges, the Rate Agreement requires the Department to submit its "Retail Revenue Requirements" to the Commission. The Rate Agreement defines Retail Revenue Requirements as the amount of Department Costs that must be recovered from Power Charges. The Rate Agreement uses the Department's submittal of its Retail Revenue Requirements as a vehicle for the Department to notify the Commission not only about Department Costs, but also about Bond Related Costs.

Revenues from Power Charges will be deposited into an "Operating Account." Funds in the Operating Account will be used to pay Department Costs, and will also be transferred to a "Priority Contract Account." The Priority Contract Account will be used to pay for the costs that the Department incurs under its Priority Long Term Power Contracts ("PLTPCs"), which have terms that require the Department to pay for power purchased under these contracts ahead of Bond Related Costs (such as Bond debt service).

In addition, the Department will fund an "Operating Reserve Account" to be drawn upon in the event that there are shortfalls in the Operating Account or the Priority Contract Account.

Revenues from Bond Charges will be deposited into a "Bond Charge Collection Account." Funds in the Bond Charge Collection Account will be transferred periodically to a "Bond Charge Payment Account." Funds in the Bond Charge Payment Account may only be used to pay Bond Related Costs. However, so long as funds remain in the Bond Charge Collection Account, they may be used to pay amounts due under the PLTPCs to fulfill the priority payment requirements of the PLTPCs. If the Bond Charge Collection Account is used to fund amounts due under PLTPCs, the Bond Charge Collection Account is to be replenished or reimbursed from Power Charges.

These Bond Charge and Power Charge accounts are further described in Section E.

The Department is making this determination of revenue requirements consistent with the requirements of Section 80110 and 80134 of the California Water Code and is providing information consistent with the requirements of the Rate Agreement.

[7] As noted above, certain charges designed to recover Department Costs may also be imposed on the customers of Electric Service Providers. The implementation of such charges would, of course, affect the amounts described in this Determination as needed to be recovered from Power Charges imposed on customers of the Department and the IOUs.

Consistent with the terms and conditions of the Rate Agreement, the Department may, depending on its operating circumstances, revise the revenue requirements contained within this Determination. The Department will notify the Commission when such a revision is warranted and provide the necessary information for the Commission to implement the appropriate Power Charges and Bond Charges during the course of the revenue requirement period.

C. RECONCILIATION OF REVENUE REQUIREMENTS IMPLEMENTED IN THE 2001–2002 RATE DECISION, WITH RESULTS OF OPERATIONS THROUGH MARCH 2002 AND UPDATED PROJECTIONS FOR THE BALANCE OF 2002

On February 21, 2002, in the 2001–2002 Rate Decision, the Commission implemented the Department's revenue requirement in the amount of $9.045 billion. This revenue requirement covered the period of January 17, 2001 through December 31, 2002.

In adopting the Department's revenue requirement, the Commission noted the Department intends to submit a true-up of prior periods each time it submits its new revenue requirement for the coming year (in this case, 2003).

The Department has reviewed the results of operations through the first quarter of 2002 and its projections for the balance of 2002. For the First Revenue Requirement Period, the revenue requirement determined hereby, $9.092 billion, is $46 million more than the $9.045 billion revenue requirement implemented by the Rate Decision This is a difference of 0.5 percent.

The reasons for the five most significant line item differences in Table C-1 are discussed below.

Contract Power and Residual Net Short

During April and May of 2002, the Department was successful in the renegotiation of 16 contracts with six different power suppliers, resulting in long-term savings, but also increasing available energy at lower costs during 2002. The projected increase of $194 million in Contract Power is more than offset by the decrease of $310 million in Residual Net Short purchases. More information pertaining to the renegotiated Power Contracts may be found in the Quasi-Legislative Record of Revenue Requirement Reasonableness Determination referenced in Appendix 3 to this filing. The Department's Long-Term Power contracts are available for viewing at the Department's web site: http://www.cers.water.ca.gov.

Ancillary Services

Ancillary Services projections have increased by $134 million or about 12 percent over the adopted amount. The Department is paying for California ISO billed Ancillary Services for the benefit of PG&E. It is assumed for purposes of this Determination that these costs will be recovered from PG&E in the future.

TABLE C-1
RECONCILIATION OF PRIOR PERIOD REVENUE REQUIREMENTS[8]
(Thousands of Dollars)

	Adopted 2001	Results 2001	Difference	Adopted 2002	Revised 2002	Difference	Total Adopted	Total Revised
Retail Sales (GWh)	58,399	55,639	(2,760)	40,394	40,674	280	98,793	96,313
Contract Power	$2,186,475	$2,090,518	($95,957)	$3,097,788	$3,387,685	$289,897	$5,284,263	$5,478,203
Residual Net Short	8,850,011	8,778,701	(71,310)	684,187	445,721	(238,466)	9,534,198	9,224,422
Ancillary Services	888,618	964,049	75,431	213,061	271,693	58,632	1,101,679	1,235,742
A&G	38,354	67,379	29,025	60,416	60,417	1	98,770	127,796
DSM	288,896	288,896	0	0	157,149	157,149	288,896	446,045
Other (Uncollectibles)	7,742	18,191	10,449	16,022	13,320	(2,702)	23,764	31,511
Total Commitments	$12,260,096	$12,207,734	($52,362)	$4,071,474	$4,335,985	$264,511	$16,331,570	$16,543,719
Led/(Lag) Accrual to Cash	(1,221,090)	(872,164)	348,926	1,210,442	675,784	(534,658)	(10,648)	(196,380)
Total Operating Expenditures	$11,039,006	$11,335,570	$296,564	$5,281,916	$5,011,769	($270,147)	$16,320,922	$16,347,339
Financing Costs	(10,481)	(9,981)	500	942,559	926,814	(157,465)	932,078	916,832
Total Expenditures	$11,028,525	$11,325,589	$297,064	$6,224,475	$5,938,582	$(285,893)	$17,253,000	$17,264,171
Revenue Lead/(Lag)	1,483,689	1,490,798	7,109	(837,556)	(1,114,807)	(277,251)	646,133	375,991
Spot Sales Revenue	(20,884)	0	20,884	(136,020)	(48,574)	87,446	(156,904)	(48,574)
Estimated Fund Balance				1,495,658	1,611,236	115,578	1,495,658	1,611,236
Total DWR Revenues Needed	$12,491,330	$12,816,387	$325,057	$6,746,557	$6,386,437	($360,120)	$19,237,887	$19,202,824
Net Borrowed Proceeds	(10,192,429)	(10,192,429)	0	0	81,274	81,274	(10,192,429)	(10,111,155)
Rounding Difference							3	
Customer Revenue Requirement	$2,298,901	$2,623,958	$325,057	$6,746,557	$6,467,711	($278,846	$9,045,461	$9,091,669

Conservation and Demand-Side Management (DSM)

When the current Revenue Requirement was adopted in February 2002, there was no provision for a 20/20 conservation program. With the approval of the program for residential customers to be effective during the summer of 2002, the Department projects a net cost for the Department in the amount of $157 million. Generally, residential Customers will receive bill credits equal to 20 percent of their electric bills if they reduce consumption by 20 percent or more when compared to the same billing period during 2000 (Customers served by SDG&E must reduce consumption by 15 percent to be eligible for a 15 percent bill credit). The program is expected to produce peak demand reduction of 57 MW (August) and energy savings of 426 GWh. Lower Department revenues, offset in part by anticipated energy savings resulting from this program, have been included in this Determination.

Lead/Lag Accrual to Cash

The increase of nearly $186 million in cash lag is primarily due to delays in collection of Ancillary Services costs from PG&E and in the timing of IOU-disputed catch-up payments. The Department anticipates the collection of the aforementioned

[8] Revenue Requirements for 2001 and 2002 were calculated on an accrual basis, and reflect revenues and expenses that on a cash basis will be received or paid in the 2003 period. This created the need for the led/lag adjustments that were an integral part of both the adopted and revised costs. For the second revenue requirement period; i.e. 2003, costs and revenues have been calculated on a cash basis and the adjustment process has been eliminated.

amounts during the Second Revenue Requirement Period and, with the conversion to a cash basis, the revenues are included in the projections for the year 2003.

The costs included in the Revenue Requirement implemented by the Commission in its decision in February 2002, were determined on an accrual basis. The results for 2001 and the revised 2002 costs included in Table C-1 are a combination of actual recorded costs through the first quarter of 2002, and an updated projection of the balance of 2002, also on an accrual basis. To comply with the requirements relating to cash flow and actual account balances associated with the Department's financing effort, its cost projections for 2003 were developed on a cash basis as opposed to an accrual basis. This change in methodology was necessary, though it makes a direct comparison between periods difficult.

D. THE DEPARTMENT'S REVENUE REQUIREMENTS FOR THE SECOND REVENUE REQUIREMENT PERIOD

Retail Revenue Requirement

For the Second Revenue Requirement Period, which commences January 1, 2003 and ends December 31, 2003, the Department's Retail Revenue Requirement consists of Power Charge-Related Costs and Revenues and Bond Charge-Related Costs and Revenues.

Power Charge-Related Costs include:

(1) Costs associated with power supply to be delivered to the Department under existing PLTPCs;

(2) Operating reserves as determined by the Department (see Table A-1);

(3) Administrative and general expenses; and

(4) Costs associated with ISO grid reliability purchases or ancillary services.

Power Charge-Related Revenues include:

(1) Revenues from Other Power sales;

(2) Interest earnings; and

(3) Customer Power Charge Revenue Requirement.

There are no provisions included in Power Charge-related costs for the procurement of the residual net short by the Department during the Second Revenue Requirement Period.

Over the Second Revenue Requirement Period, the Department projects that it will incur the following costs: (a) $4.120 billion in costs for long-term power contract purchases to cover the net short requirement of the Customers; (b) $170 million to acquire ancillary services and associated energy not otherwise provided by the IOUs from their retained generation; (c) $28 million in administrative and general expenses; (d) no net transfers to Bond Charge accounts to meet trust indenture requirements are needed; and (e) $517 million in charges to Power Charge accounts. This results in a total of $4.836 billion in operating and non-operating costs.

Funds to meet these costs are provided from (a) $129 million from power sales revenues to the spot market; (b) $59 million of interest earned on Power Charge account balances; and (c) $4.648 billion from Retail Customer Power Charges.

Table D-1 provides a quarterly review of costs and revenues associated with the Power Purchase Program.

TABLE D-1
POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE: RETAIL CUSTOMER POWER CHARGE CASH REQUIREMENT

Line	Description	Amounts for Revenue Requirement Period ((Millions of Dollars) 2003-Q1	2003-Q2	2003-Q3	2003-Q4	Total
1	***Power Charge Account Expenses***					
2	Power Costs	$917	$837	$1,223	$1,144	$4,120
3	Ancillary Services	61	32	28	49	170
4	Administrative and General Expenses	7	7	7	7	28
5	Debt Service	—	—	—	—	—
6	Net Transfers from/(to) Bond Charge Accounts	—	—	—	—	—
7	Net Changes to Power Charge Account Balances	133	(20)	110	295	517
8	**Total Power Charge Account Expenses**	**$1,118**	**$856**	**$1,368**	**$1,495**	**$4,836**
9	***Power Charge Account Revenues***					
10	Surcharge Revenues	—	—	—	—	—
11	Other Power Sales Revenues	16	43	31	39	129
12	Interest Earnings on Power Charge Account Balances	25	—	34	—	59
13	Net Loan Proceeds	—	—	—	—	—
14	Retail Customer Power Charge Revenue Requirement	1,076	813	1,303	1,456	4,648
15	**Total Power Charge Account Revenues**	**$1,118**	**$856**	**$1,368**	**$1,495**	**$4,836**

Bond-Related Costs include:

(1) Debt Service Payments; and

(2) Changes to Bond Charge Account Balances.

Bond-Related Revenues include:

(1) Interest earned on Bond Account Balances;

(2) Transfers from Power Charge Accounts; and

(3) Customer Bond Charge Revenue Requirement.

Table D-2 provides a quarterly summary of expected Bond Related Costs and Revenues for the Second Revenue Requirement Period.

TABLE D-2
POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE:
RETAIL CUSTOMER BOND CHARGE CASH REQUIREMENT

Line	Description	Amounts for Revenue Requirement Period ((Millions of Dollars) 2003-Q1	2003-Q2	2003-Q3	2003-Q4	Total
1	***Bond Charge Account Expenses***					
2	Debt Service Payments	$36	$279	$36	$279	$632
3	Other Bond Charge Account Expenses	—	—	—	—	—
4	Net Changes to Bond Charge Account Balances	231	(15)	301	18	535
5	**Total Bond Charge Account Expenses**	**$268**	**$264**	**$337**	**$298**	**$1,167**
6	***Bond Charge Account Revenues***					
7	Interest Earnings on Bond Charge Account Balances	1	—	26	—	27
8	Revenue Bond Net Proceeds	—	—	—	—	—
9	Net Transfers from/(to) Power Charge Accounts	—	—	—	—	—
10	Retail Customer Bond Charge Revenue Requirement	266	264	312	298	1,140
11	**Total Bond Charge Account Revenues**	**$268**	**$264**	**$337**	**$298**	**$1,167**

Over the Second Revenue Requirement Period, the Department projects that it will incur the following costs related to Bond Requirements: (a) $632 million for payments to meet Debt Service requirements and (b) $535 million for Changes to Bond Charge account balances, resulting in total Bond Charge Account expenses of $1.167 billion.

Funds to meet these requirements are provided from (a) $27 million in Interest Earned on Bond Charge account balances; (b no Net transfers from Power Charge Accounts are required; and (c) $1.140 billion from Customers' Bond Charges.

Added together, the Department's total Power and Bond costs are $6.003 billion. Revenues from interest earned and Other Power Sales are $215 million, resulting in combined Customer Revenue Requirements of $5.788 billion.

E. ASSUMPTIONS GOVERNING THE DEPARTMENT'S PROJECTION OF REVENUE REQUIREMENTS FOR THE SECOND REVENUE REQUIREMENT PERIOD

The Department's estimate of its Retail Revenue Requirements for the period January 1, 2003, through and including December 31, 2003, are based on a number of assumptions regarding sales, power supply, natural gas prices, off-system sales, the costs of ancillary services, demand side management and conservation and, administrative and general expenses. Revenues and expenses for the Second Revenue Requirement Period were calculated on a cash basis rather than on an accrual basis as was utilized during the First Revenue Requirement Period. This change was required to meet the cash reporting requirements associated with the bond financing.

Load and Sales Forecast

As the starting point for its estimates of IOU demand and energy requirements, the Department obtained the most recent forecasts of customer loads from each IOU. The forecasts and underlying assumptions (including economic and population growth, price elasticity, programmatic and behavioral conservation, and rate of rebound from the decline in sales observed in 2001) were discussed with staff from the Load Forecasting Departments of each of the IOUs. The forecasts received from the IOUs were compared with other relevant sources including, recorded IOU sales data, forecasts prepared by the California Energy Commission ("CEC"), the CAISO, and the Western Energy Coordinating Council ("WECC"). A loss factor was applied to the IOU estimates of sales at the customer's meter to obtain the total amount of energy required to meet customer electricity requirements. The loss factors were discussed with staff from each of the IOUs and were determined to be reasonable. The loss factors utilized in developing the estimate of the electricity requirements were:

Utility	Distribution	Transmission	Total
PG&E	7.0%	2.0%	9.0%
SCE	7.4%	1.6%	9.0%
SDG&E	4.0%	1.8%	5.8%

Each IOU forecast was developed using econometric models. The models rely on a statistical analysis of historical data to develop regression equations that relate changes in "independent" variables (such as employment growth) to "dependent" variables (such as electricity sales by end-user segment). The resulting equations, together with forecasts of electricity prices, weather conditions, and key economic drivers, are used to predict sales by revenue class. To improve accuracy, the projections may be modified by the IOUs to account for current trends, judgment, or other events not specifically addressed in the models.[9]

[9] The IOUs' load forecasts and forecasting models have received detailed scrutiny in numerous regulatory proceedings over the years. In addition to scrutiny by the Commission, the Federal Energy Regulatory Commission ("FERC"), and numerous regulatory interveners, the Commission's Office of Ratepayer Advocates customarily reviews and critiques the

Table E-1 presents the major assumptions employed in the IOU forecasts utilized by the Department for the purpose of this revenue requirement determination. The economic forecast for Pacific Gas and Electric Company (PG&E) was based on a forecast of economic growth in PG&E's service area prepared by Economy.com. Southern California Edison Company ("SCE") derived its economic assumptions from a national and statewide forecast prepared by Data Resources Inc. ("DRI"), while San Diego Gas and Electric Company ("SDG&E") relied on a DRI forecast of economic trends in its service area.

TABLE E-1
MAJOR ASSUMPTIONS USED IN THE LOAD FORECASTS OF THE INVESTOR-OWNED UTILITIES

	PG&E	SCE	SDG&E
Growth Assumptions:			
Population Growth[1]	1.0	1.8	1.4[3]
Number of Households[1]	1.3	1.0	1.7[3]
Non-Farm Employment[1,2]	1.0	1.1	2.1[3]
Heating Degree Days	20-Yr. Avg.	30-Yr. Avg.	20-Yr. Avg.
Cooling Degree Days	20-Yr. Avg.	30-Yr. Avg.	20-Yr. Avg.

Source: PG&E data from work papers submitted in PG&E's Notice of Intent for its 2003 GRC. SCE data from Notice of Intent for Test Year 2003 GRC. SDG&E data provided by the IOU.
[1] Percent per year increase during 2002 and 2003, except as noted.
[2] Actual growth during 2001 was 1.2 percent statewide, according to the State Department of Finance.
[3] Annual percent growth from 2000 through 2006.

The initial IOU load forecasts were adjusted for several factors including self-generation, direct access, conservation and load management, and price elasticity.

Sources of IOU Forecasts

The IOUs typically do not issue new demand forecasts annually. For PG&E, the Department was provided, and relied upon a forecast prepared by PG&E in April 2002 for PG&E's 2003 General Rate Case ("GRC"). The forecast projects total retail energy requirements of 77,461 GWh in 2002. Based on information provided by PG&E, this amount was escalated by 1.5 percent to determine 2003 energy requirements at the customer's meter (78,623 GWh).

The projection provided by SCE was prepared in May 2001 and is being used for SCE's Test Year 2003 GRC. SCE forecasts 2003 sales at the customer's meter to be 79,410 GWh.

SDG&E provided a forecast prepared in the second half of 2001. In the forecast, 2003 energy requirements at the customer's meter are projected to be 18,780 GWh.

IOUs' forecasts based on its own independent load forecasts using its own econometric models. Typically, the differences between the IOUs' forecasts and those prepared by the Office of Ratepayer Advocates have been small. The high level of scrutiny of these forecasts by regulatory agencies and the acceptance of the projections for revenue allocation and rate setting purposes provide support for the reasonableness of the IOUs' forecasting efforts.

Elements of the forecast have been used in various Commission proceedings, including the direct access exit fee proceedings.

Hourly Load Shapes

SCE provided the composite and direct access load shapes for the Department's use. SDG&E provided the composite load shape for use by the Department. The load shape for SDG&E's direct access was estimated using class specific load profiles from SDG&E's website. PG&E did not provide the composite load shape information. Therefore, composite load shape information contained in PROSYM for the 1993-98 period was used to determine peak demand and perform price forecasting and market simulation. The direct access load shape was estimated based on the static load profiles for the various customer classes from PG&E's website, weighted by their respective shares of direct access volumes

Self-Generation

To determine the outlook for self-generation, the Department prepared a forecast of the potential increase in self-generating capacity in the IOU service areas. The forecast considered a range of factors that could increase self-generation capacity, including: (a) self-generation and/or renewable resource incentive programs and initiatives administered by the CEC, the Commission, the California Consumer Power and Conservation Authority (Power Authority), and the CAISO; (b) recent price increases, suspension of direct access, increased concerns over service reliability, and ongoing efforts to standardize interconnection requirements through the Commission's Rule 21 proceedings; and (c) potential barriers and market restraints to the expansion of self-generation. The Department expects these factors to result in a total increase in self-generating capacity of 370 MW by 2003. It was assumed that 20 percent of the capacity is installed at the premises of direct access customers. The remaining 80 percent is estimated to be installed at the sites of customers whose energy requirements are supplied by the IOUs and the Department. This capacity was allocated among the IOUs based on their respective shares of reported self-generation activity. The allocation percentages were: PG&E 35 percent, SCE 45 percent, and SDG&E 20 percent. An availability factor of 80 percent was applied to estimate peak capacity and a factor of 70 percent was applied to calculate energy.

The forecasted self-generation is believed to be incorporated in the IOU forecasts.[10] Therefore, the estimate of self-generation does not result in a net reduction in energy and demand requirements compared with the forecasts prepared by the IOUs. Trends in self-generation capacity will be monitored and the assumptions will be revisited if circumstances warrant.

[10] PG&E and SDG&E do not have explicit forecasts of incremental self-generation capacity installed by end use customers in their service areas. SCE's explicit forecast of self-generation was limited to projects that SCE has identified as being in construction. Their econometric models are based on historical data and thus some self-generation capacity is implicitly included in the forecasts. Given the low demand growth rates in the utilities' forecasts, the Department concluded that no reductions in sales forecasts for additional self-generation should be made.

Direct Access

The Proposed Determination indicated that, in accordance with the provisions of AB1X, the Commission issued an interim order suspending direct access effective September 20, 2001. A final order affirming the September 20, 2001 suspension date was issued by the Commission on March 21, 2002 (the "Direct Access Order"). Electric end-users that elected to acquire service from alternative suppliers on or before September 20, 2001, will continue to be eligible for direct access service. The Commission estimates that approximately 14 percent of total IOU load qualified for direct access service under the Direct Access Order. The Direct Access Order:

- States that direct access will remain suspended until the Department is no longer providing power to the Customers.
- Prohibits the IOUs from accepting any new Direct Access Service Requests not already approved by the Commission, including requests from existing qualified direct access end-users that wish to add new direct access locations or accounts to their service.[11]
- Contemplates the possible establishment by the Commission, at a future date, of a charge on direct access Customers ("direct access charge"). The direct access charge will be set at a level that prevents cost shifting as a result of direct access.[12]

The proposed Determination assumes no incremental participation in direct access, beyond that authorized by the Direct Access Order.

As a result of comments received as part of the public process initiated by the Department (as described in Section A of this Determination), and the receipt of additional information from the IOUs, the Department has revised the estimate of each of the IOUs load under direct access service. The following table shows the percentage of each IOU's load taking direct access used in the proposed Determination dated June 14, 2002 (Column A). The revised percentages now utilized are reflected in Column B. The Final Determination assumes that 13.8 percent of total IOU loads are served through direct access.

[11] However, these customers may renew their direct access service contracts upon their expiration or transfer them to a new service location as long as the load served is of comparable size.

[12] That is, the Department's charges (Bond Charges and Power Charges) to the remaining Customers would not increase due to Customers participating in direct access. The Commission has not established an order relative to direct access charges, but has indicated such fees would be applied to Customers that switched to direct access service between July 1, 2001, the date the Commission first considered suspension of direct access, and September 20, 2001, the final suspension date ordered by the Commission. This Determination makes no assumptions regarding revenues that might be realized by the Department from direct access charges.

	(A) Percentage of Load Proposed Determination dated June 14, 2002	(B) Percentage of Load Final Determination
Pacific Gas and Electric Company	14.8%	11.2%
Southern California Edison Company	11.0%	15.1%
San Diego Gas and Electric Company	20.1%	19.5%
Statewide	13.6%	13.8%

Conservation and Load Management

The IOU load forecasts are based on historical data through 2001 and therefore reflect both programmatic and behavioral conservation. Energy conservation impacts from both the conservation programs and behavioral responses are likely to persist and depress growth rates for electricity demand during the second revenue requirement period. The low rates of demand growth in the utilities forecasts reflect the persistence of this conservation effect. The 20/20 program was implemented in 2001 and again in 2002, for specific months. There has been no projection of an extension of this program in the development of this Determination for the year 2003.

PG&E Sales to Western Area Power Administration ("WAPA")

Contract 2948A, signed in 1967, governs the interconnection of PG&E's and WAPA's transmission and distribution systems and the integration of their loads and resources. The contract allows Western to integrate PG&E's fossil-fueled and other generating resources with the hydropower resources of the federal Central Valley Project ("CVP") and deliver this "firmed" energy to preference power customers—generally government and municipal entities—pursuant to Federal reclamation law. In return, PG&E receives access to surplus CVP hydroelectric generation which is less expensive than other resources available to PG&E. Virtually all of WAPA's 73 preference power customers are located in the PG&E service region in northern California.

During 2003, PG&E is assumed to provide 5,146 GWh of firming energy to WAPA. The forecast is based on invoiced PG&E sales through March 2002 and estimates for the remaining months. The forecasts for April 2002 and beyond were based on WAPA's March 29, 2002 rolling 12-month forecast of preference power customer loads, CVP hydroelectric generation, U.S. Bureau of Reclamation pumping requirements, and other factors. WAPA based its forecast on the Bureau's latest available forecast of CVP water flows at a 50 percent exceedence level.

The Department modeled PG&E sales to WAPA in PROSYM as a "negative bilateral" that reduces PG&E's Utility Retained Generation (URG) and thereby increases the quantity of energy supplied by the Department. The sale is modeled as a base load contract and the peak MW for each month is computed by dividing the monthly energy by the number of hours in the month. While this may somewhat overstate the peak MW provided to WAPA during the summer months, the impact on the Department's overall revenue requirement is not believed to be material. There are no comparable "other load requirements" for the other IOUs.

Peak Load and Energy Calculations

Table E-2 provides the peak megawatt demand for each IOU in 2003. Based on their respective load shapes, the total peak demand for PG&E occurs in July 2003 while the peak demands of SCE and SDG&E occur in August 2003. The total IOU peak demand is the sum of the individual peaks. Due to load diversity, the coincident peak computed in PROSYM is likely to be lower.

TABLE E-2
ESTIMATED PEAK DEMAND[13]

	Amounts for the Revenue Requirement Period (Megawatts)
Pacific Gas and Electric Company	
Peak Demand[14]	17,206
Less:	
Self-Generation	90
Direct Access	1,726
Peak Demand After Adjustments[15]	15,390
Southern California Edison Company	
Peak Demand	18,247
Less:	
Self-Generation	116
Direct Access	2,363
Peak Demand After Adjustments	15,768
San Diego Gas and Electric Company	
Peak Demand	3,935
Less:	
Self-Generation	50
Direct Access	630
Peak Demand After Adjustments	3,255
All Investor-Owned Utilities	
Peak Demand	39,388
Less:	
Self Generation	256
Direct Access	4,719
Peak Demand After Adjustments[16]	34,413

[13] All values presented in the table have been adjusted for transmission and distribution losses. Amounts shown for self-generation represent increases above levels experienced historically.
[14] Includes adjustments due to price elasticity effects.
[15] For all three IOUs, these amounts are intended to represent peak demands that must be met by electric generating resources or power purchases or a combination of the two.
[16] Represents the sum of the individual IOU amounts. The actual value at the time of the system's coincident peak may be lower.

Table E-3 shows the estimated gigawatt hours of energy requirements expected during 2003.

TABLE E-3
ESTIMATED ENERGY REQUIREMENTS[17]

	Amounts for the Revenue Requirement Period (Gigawatt-Hours)
Pacific Gas and Electric Company[18]	
Energy Requirements[19]	86,253
Less:	
Self-Generation	554
Direct Access	9,482
Energy Requirements After Adjustments[20]	76,217
Southern California Edison Company	
Energy Requirements	87,269
Less:	
Self-Generation	712
Direct Access	12,942
Energy Requirements After Adjustments	73,615
San Diego Gas and Electric Company	
Energy Requirements	20,177
Less:	
Self-Generation	307
Direct Access	3,731
Energy Requirements After Adjustments	16,139
All Investor Owned Utilities	
Energy Requirements	193,699
Less:	
Self-Generation	1,573
Direct Access	26,155
Energy Requirements After Adjustments	165,971

Power Supply-Related Assumptions

Two types of power supplies needed to meet the requirements of the three IOUs were considered by the Department in its determination of revenue requirements: (a) Supply from Priority Long-Term Power Contracts and (b) the Residual Net Short of the three IOUs.[21]

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[17] All values presented in the table have been adjusted for transmission and distribution losses. Amounts shown for self-generation represent increases above levels experienced historically.

[18] Amounts shown exclude 5,146 GWh of requirements associated with the company's contract with the Western Area Power Administration ("WAPA").

[19] For all three utilities, includes adjustments on account of price elasticity effects.

[20] For all three IOUs, these amounts are intended to represent energy requirements that have to be met by electric generating resources or power purchases or a combination of the two.

[21] While the Department has calculated and presented the residual net short requirements of the IOUs, pursuant to AB1X, the Department has not made any provision for the cost of the residual net short requirements in its Determination for the Second Revenue Requirement Period. The section titled "Key Uncertainties in the Revenue Requirement Determination" provides more detail on the issue of supply to meet residual net short requirements during the Second Revenue Requirement Period.

Table E-4 below shows, for the Second Revenue Requirement Period, the estimated peak demand for each of the three IOUs, the estimated peak demand after adjustments, estimated supplies from generation retained by the three IOUs,[22] the resulting net short, the expected supply from the Department's Priority Long-Term Power Contracts, and the Residual Net Short.

TABLE E-4
ESTIMATED NET SHORT, SUPPLY FROM PRIORITY LONG-TERM POWER CONTRACTS AND THE DEPARTMENT'S ESTIMATE OF THE RESIDUAL NET SHORT

	Amounts for the Revenue Requirement Period (Megawatts)
Pacific Gas and Electric Company	
Peak Demand[23]	17,206
Peak Demand After Adjustments	15,390
Supply from Utility Retained Generation	10,410
Net Short	4,980
Supply from the Department's Priority Long Term Power Contracts	5,271
Residual Net Short (Surplus)	(291)
Southern California Edison Company	
Peak Demand	18,247
Peak Demand After Adjustments	15,768
Supply from Utility Retained Generation	9,450
Net Short	6,318
Supply from the Department's Priority Long-Term Power Contracts	4,527
Residual Net Short (Surplus)	1,790
San Diego Gas and Electric Company	
Peak Demand	3,935
Peak Demand After Adjustments	3,255
Supply from Utility Retained Generation	913
Net Short	2,342
Supply from the Department's Priority Long-Term Power Contracts	1,345
Residual Net Short (Surplus)	997

22 For purposes of this Determination, generation retained by the three IOUs is defined as the sum of generation owned by the IOUs, supply from contracts between the IOUs and qualifying facilities ("QF's") and other bilateral contracts.
23 See the discussion under "Load and Sales Forecast Assumptions" for an explanation of the source of data on peak demand for each of the three IOUs.

Table E-5 below presents similar information for the three IOUs in terms of energy requirements during the Second Revenue Requirement Period.

TABLE E-5
ESTIMATED NET SHORT, SUPPLY FROM PRIORITY LONG-TERM POWER CONTRACTS AND THE DEPARTMENT'S ESTIMATE OF THE RESIDUAL NET SHORT

	Amounts for the Revenue Requirement Period (Gigawatt-Hours)
Pacific Gas and Electric Company	
Energy Requirements	86,253
Energy Requirements After Adjustments	76,217
Supply from Utility Retained Generation	52,756
Net Short	23,461
Supply from the Department's Priority Long Term Power Contracts	21,836
Off-System Sales of Excess Contract Energy[24]	(2,707)
Residual Net Short (Surplus)[25]	4,332
Southern California Edison Company	
Energy Requirements	87,269
Energy Requirements After Adjustments	73,615
Supply from Utility Retained Generation	57,880
Net Short	15735
Supply from the Department's Priority Long Term Power Contracts	22,246
Off-System Sales of Excess Contract Energy	(7,823)
Residual Net Short (Surplus)	1,312
San Diego Gas and Electric Company	
Energy Requirements	20,177
Energy Requirements After Adjustments	16,139
Supply from Utility Retained Generation	7,056
Net Short	9,083
Supply from the Department's Priority Long Term Power Contracts	6,953
Off-System Sales of Excess Contract Energy	(207)
Residual Net Short (Surplus)	2,337

[24] Represents the aggregate energy purchased under the Department's Long-Term Priority Contracts that is in excess of the energy needed to meet the hourly residual net short requirements of the IOUs.

[25] There is a slight difference in the GWh of Residual Net Short shown here for each of the IOUs compared to that included in the Financial Model. This is due to a calculation process in ProSym relating to hourly vs. monthly roll-up of numbers. The total difference for all three IOUs is 85 GWh.

Table E-6 shows the peak capacity and energy supplied by the Department's long-term contracts on an annual basis for the Second Revenue Requirement Period. This information is provided by zone (i.e., SP15 and NP15) and by type of resource.

TABLE E-6
PEAK CAPACITY AND ANNUAL ENERGY SUPPLIED FROM THE DEPARTMENT'S PRIORITY LONG-TERM POWER CONTRACTS

	Peak Capacity[26] (MW)	Energy (Gigawatt-hours)
Contract Capacity and Energy		
SP 15		
Base Load[27]	1,610	11,110
Peak[28]	2,422	10,416
Dispatchable	1,780	6,393
Renewable/As-Available	60	524
Off-Peak[29]	200	757
Total SP 15	5,872	29,200
NP 15		
Base Load	2,050	15,831
Peak	1,003	2,735
Dispatchable	2,175	2,915
Renewable/As-Available	43	354
Off-Peak	-	1
Total NP 15	5,271	21836
Total Contract Capacity and Annual Energy[30]	11,143	51,035

For informational purposes, Table E-7 shows, for the Second Revenue Requirement Period, the expected average cost (in $/MWh) by quarter for the Department's Priority Long Term Power Contracts, the expected cost of Residual Net Short, and the volume weighted average of the two.

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26 Peak loads can vary by area within California. The Department has assumed that the peak month is July.

27 Base Load contracts provide full capacity and energy during all months of the year.

28 Peak contracts generally provide full capacity and energy, Monday through Saturday, from hour ending 0700 through hour ending 2200 each month of the year. Note that this grouping also includes a sub-set of contracts that provide full capacity and energy seven days a week from hour ending 0700 through hour ending 2200 for all months of the year as well as a sub-set of contracts that provide full capacity and energy Monday through Friday from hour ending 0700 through hour ending 2200 for all months of the year.

29 Off-peak contracts provide full capacity and energy during those hours not generally defined as peak. Off-peak capacity amounts are not added to total peak capacity supply.

30 Total Contract Capacity excludes capacity provided by the Department's off-peak contracts.

TABLE E-7
ESTIMATED POWER SUPPLY COSTS
(Dollars per Megawatt-Hour)

	Long-Term Priority Contracts	Residual Net Short[31]	Weighted Average[32]
Quarter 1 – 2003	82	35	73
Quarter 2 – 2003	83	29	78
Quarter 3 – 2003	82	38	76
Quarter 4 – 2003	78	35	72

Table E-8 shows, quarterly for the Second Revenue Requirement Period, estimated net short volumes in gigawatt-hours, supply from Priority Long-Term Power Contracts, and the Residual Net Short.

TABLE E-8
NET SHORT, SUPPLY FROM PRIORITY LONG-TERM POWER CONTRACTS, OFF-SYSTEM SALES AND RESIDUAL NET SHORT IN 2003

Period	Net Short (GWh)	Supply from Long-Term Priority Contracts (GWh)	Priority Long-Term Power Contract Costs (Millions of Dollars)	Off System Sales Volumes (GWh)	Revenues from Off System Sales (Millions of Dollars)	(Residual Net Short)[33] Spot Volume (GWh	(Residual Net Short)Spot Purchases (Millions of Dollars)
Q1-2003	11,293	10,465	$859	-1,736	$22	2,563	$91
Q2-2003	8,566	11,234	930	-3,765	43	1,096	32
Q3-2003	15,814	15,479	1,268	-1,866	26	2,200	84
Q4-2003	12693	13,856	1,076	-3,370	51	2,207	77
Total (1)	48366	51034	$4,133	-10,737	$142	8,066	$284
(1) May not add due to rounding.							

Natural Gas Price-Related Assumptions

Since mid-2000, natural gas prices in California have fluctuated widely, driven by variations in weather patterns, supply availability, pipeline constraints, and storage inventory levels. In recent months, gas prices have moderated and the Department believes the long-term trend will exhibit a flattening of the price curve, with modest increases in price over the Second Revenue Requirement Period. Between 1996 and 2000, natural gas prices demonstrated a relatively stable pattern, generally averaging

[31] As mentioned earlier, this determination of the Department's revenue requirements assumes that the Department, pursuant to AB1X, is not responsible for providing resources to meet the residual net short of the three IOUs during the Second Revenue Requirement Period. The next section titled "Key Uncertainties in the Revenue Requirement Determination" discusses the implications of a continued role for the Department in providing the residual net short requirement of the three IOUs.

[32] This represents the sum of long term priority contract costs and estimated residual net short costs divided by the sum of long term priority contract and residual net short volumes.

[33] As mentioned earlier, this determination of the Department's revenue requirements assumes that the Department, pursuant to AB1X, is not responsible for providing resources to meet the residual net short of the three IOUs during the Second Revenue Requirement Period.

approximately $2.20 per MMBtu at Henry Hub on an annual basis. This price behavior changed in May 2000, when prices failed to decline following the end of the winter heating season, despite excess gas in underground storage. As a result of the relatively high price, many buyers delayed purchasing gas for storage injection, expecting prices to decline as summer progressed. The decision to delay these purchases, together with other factors, contributed significantly to major increases in the cost of natural gas during the latter half of 2000 and early 2001. Over the course of 2001, gas prices began to retreat to lower levels. These reductions were influenced by lower than expected demand for natural gas-fired generation during the summer of 2001, an increase in new gas drilling and production levels (driven by the higher prices experienced during 2000), and the gradual slowing of the national and California economies.

The Department has estimated forward natural gas prices using a proprietary forecasting model. The model relates annual natural gas prices to prior period prices, a weather variable reflecting average heating degree-days, and a variable representing drilling activity and well completions to produce a forward price at Henry Hub. The resulting econometric equation is used to estimate future prices. The econometric results of the Department's modeling exhibit strong and reasonable properties in terms of statistical error measurements and, when data inputs are used that reflect historical conditions, the model has produced price estimates that are very close to those actually experienced.

The delivered cost of natural gas is typically the cost at the southern California border plus the cost of intrastate transportation. Southern California border prices are derived by adding a "basis" differential to the Henry Hub price. Resulting gas prices at the Southern California border, Malin, and PG&E's city-gate by quarter for the Second Revenue Requirement Period are shown in Table E-9.

TABLE E-9
NATURAL GAS PRICE ASSUMPTIONS
(Dollars per mmBTU)

	SoCal Border	Malin	PG&E City Gate
Q1 – 2003	3.16	2.69	3.14
Q2 – 2003	3.22	2.74	3.20
Q3 – 2003	3.07	2.61	3.06
Q4 – 2003	3.38	2.88	3.35

Assumptions Relating to Spot (Off-System) Sales

As with any retail provider of energy, the Department, from time to time, will purchase more energy than is required to serve its retail customers. This excess energy is sold in wholesale markets in an attempt to provide income to the Department that is used to decrease the Department's revenue requirements to be recovered from the Customers.

The expected average quarterly cost and volume of off-system sales projected to be made by the Department over the Second Revenue Requirement Period is provided in Table E-10 below.

TABLE E-10
OFF-SYSTEM SALES

	Off-System Sales Volume (GWh)	Off-System Sales Revenue (Millions of Dollars)	Weighted Average Cost ($/MWh)
Q1 – 2003	1,736	$22	$13
Q2 – 2003	3,765	43	$12
Q3 – 2003	1,866	26	$14
Q4 – 2003	3,370	51	$15
Total	10,736	$142	$13

Assumptions Relating to Ancillary Service Costs

The Department continues to be authorized to take those actions necessary to implement and administer the power supply contracts in effect as of December 31, 2002, and to ensure delivery of power thereunder to retail end-use customers. To the extent that the Department must pay for or obtain ancillary services charges from the CAISO for scheduling and delivery of power, it continues to have the authority to do so under AB1X.

The volume of ancillary services required in any given hour is based on the load scheduled for that hour. The price for ancillary services is based on prices that result from the day-ahead and hour-ahead bids for such services that the CAISO receives from its ancillary services auction process.

To develop an estimate of expected ancillary service costs for the Department's revenue requirements, it has identified a correlation between energy prices and ancillary services prices. Based on hourly historical price data for the period from April 1998 through December 2000, a regression analysis was performed resulting in an econometric model of ancillary service price (where spinning reserves were used as a proxy for ancillary services) as a function of several variables. Upon performing the regression, the Department identified the price of the residual net short as the primary independent variable driving the price of ancillary services.

To develop the price forecast, the energy market-clearing price forecast and the system load were analyzed using the econometric model. Simulations were then conducted to calculate the forecasts of prices as well as the distributions and confidence intervals of the prices. Based on these simulations, the Department estimates its cost of ancillary services, as calculated below[34]:

[Cost of Ancillary Services = 3.8 percent x Price of Residual Net Short x Power Supplied by DWR]

[34] The allowance for the costs of future ancillary services through the Second Revenue Requirement Period assumes that the Department does not credit back CAISO transactions on behalf of the IOUs.

In addition to these costs, the Department may be required to pay Grid Management Charges ("GMC") imposed by the CAISO. The Department's estimate of the GMC for the Second Revenue Requirement Period is shown below.

Service Type	CAISO Tariff ($/MWh)
Control Area Services	0.58
Congestion Management	0.37
Ancillary & Real-Time	0.96
Total	1.90

The $1.90 charge for GMC and the projection of ancillary services costs are estimates of potential charges the Department expects to incur if the Department is required to pay CAISO GMC and ancillary services costs on Department delivered energy.

In addition, the Department contracted with the APX to provide a minimum of 250 MW per month by October 2002 and 500 MW per month by June 2003 of load serving capability. There are also options whereby the APX could provide up to 1,000 MW of demand response by June 2003, if both parties agree and if minimum performance goals are met. The contract will extend from July 2002 through May 2007. This capacity is to be available to the Department for up to 24 hours per month for either meeting peak load requirements or providing ancillary services. The ability to use the capacity for ancillary services (non-spin and replacement reserves) is not limited to 24 hours per month. The reserves can be used for any hour until they have been called upon for 24 hours within a calendar month (non-spin and replacement reserves are called upon for only a portion of the hours that they are available. Based on the foregoing, the Department estimates that its cost of ancillary services over the Second Revenue Requirement Period will be approximately $170 million for services in support of DWR power sales to retail end-use customers.

If the Department is not required to pay for ancillary services costs in 2003, the total revenue requirement would decrease by $170 million.

Administrative and General Costs

The Department's administrative and overhead costs of $28 million included in Power Charges consist of its labor costs, including benefits, professional service fees, capital expenditures attributable to its role in the acquisition and management of power supply resources to meet the Customers' net short requirements, and costs billed by the IOUs under the Servicing Arrangements. These costs have been estimated for 2003 based on approved budget levels. The Department's estimate of administrative and general expenses for the Second Revenue Requirement Period are predicated on the transfer of responsibility for the procurement of residual net short purchasing requirements to a party other than the Department beginning January 1, 2003.

Financing-Related Assumptions

The Department expects to issue Power Supply Revenue Bonds late in the third quarter or early in the fourth quarter of 2002. The primary uses of net Bond proceeds will be to (a) repay the then-outstanding balance of the $4.3 billion Interim Loan entered into by the Department with commercial lenders, the proceeds of which were used to fund 2001 power costs; (b) reimburse the State's General Fund for approximately $6.1 billion advanced to the Department for 2001 power purchases and interest that has accrued on the General Fund advances,[35] and (c) fund reserves required to complete the bond financing.

The Department and the Commission have approved the "Summary of Material Terms of Financing Documents" referenced in the Rate Agreement as well as an "Addendum to Summary of Material Terms". Any material changes to the financing parameters beyond what is described in the Summary of Material Terms and the Addendum must be approved by the Commission prior to the issuance of the Bonds. The following are key provisions of the Summary of Material Terms and the Addendum:

(1) The maximum "net proceeds" from the sale of the Bonds will not exceed $11.95 billion.

(2) The final maturity of the bonds will be no less than 19 years and no more than 21 years from the date of issuance of the first series of Bonds.

(3) The summary describes the flow of funds into, within, and between various accounts established under the Bond Indenture.

(4) The summary specifies the methodology for sizing reserves and fund and account balances.

(5) The summary prescribes the maximum level of initial funding for each of the Department's operating and financing-related accounts.

Based on the provisions of the Rate Agreement, Summary of Material Terms and the Addendum to Summary of Material Terms, the Department estimates that the Bond Charge-related revenue requirement for the Second Revenue Requirement Period will be $1.140 billion.[36]

Accounts and Flow of Funds Under the Indenture

The terms agreed to in the Rate Agreement and Summary of Material Terms with all applicable addenda will be reflected in a bond indenture that serves as the principal

[35] The Department's November 5, 2001 determination of revenue requirements discusses in greater detail the factors that have driven the Department's indebtedness.
[36] Note that this estimate of financing costs excludes amounts associated with debt service reserves. The determination of the exact amount of the initial debt service reserve will be performed as the date for the bond issuance draws closer. Once this determination has been made, the Department will notify the Commission of the impact, if any, on the Bond Charge.

agreement between the Department and bond holders (the "Indenture"). The following is a description of the funds and accounts that are anticipated to be required as part of the Bond program. The final level of funding of these funds and accounts, and the formulas used to determine their ongoing balances and the specific application of moneys within such funds and accounts are subject to final modification as required by the rating agencies, bond credit enhancers and investors in order to complete the sale of the estimated $11.75 billion in bonds.

Revenues are held in and accounted for in the Electric Power Fund established under AB1X. The Indenture will establish two sets of accounts for Revenues within the Electric Power Fund. In the following description of accounts and the flow of funds, capitalized terms refer to terms that will be further defined in the Indenture.

One set of accounts is primarily for the deposit of Power Charge Revenues and the payment of Operating Expenses (including payments of Priority Contract Costs and other power purchase costs and other costs of the Power Supply Program) (collectively, the "Power Charge Accounts"):

- The Operating Account,
- The Priority Contract Account,
- The Operating Reserve Account, and
- The Administrative Cost Account.

The other set of accounts is primarily for the deposit of Bond Charge Revenues and the payment of Bond Related Costs (collectively, the "Bond Charge Accounts"):

- The Bond Charge Collection Account,
- The Bond Charge Payment Account, and
- The Debt Service Reserve Account.

The Indenture will require all Bond Charge Revenues to be deposited in the Bond Charge Collection Account and all Power Charge Revenues and other Revenues (other than Bond Charge Revenues) to be deposited in the Operating Account.

Operating Account

The Department will covenant to include in its revenue requirements amounts sufficient to cause a "Minimum Operating Expense Available Balance" to be on deposit in the Operating Account. The Minimum Operating Expense Available Balance is to be calculated by the Department at the time of each determination of a revenue requirement. The Minimum Operating Expense Available Balance for so long as the Department continues to purchase the Residual Net Short, may be an amount up to and including $1 billion, and thereafter will be an amount equal to the largest projected difference between the Department's projected operating expenses and the Department's projected Power Charge revenues during any one month period during the then current revenue requirement period, taking into account a range of possible future outcomes.

The Department projects that at the time of the closing of the last series of Bonds, $1.26 billion will be required to be on deposit in the Operating Account. Assuming the General Fund advances are fully repaid through the issuance of the Bonds, the initial funding of the account will be from a combination of Bond proceeds and monies available in the Electric Power Fund at the time of the Bond closing.

Priority Contract Account

The Priority Contract Account will be used to pay the costs the Department incurs under its Priority Long Term Power Contracts, which have terms that require the Department to pay for power purchased under these contracts ahead of Bond Related Costs. On or before the fifth Business Day of each month, the Department is required to transfer from the Operating Account to the Priority Contract Account such amount as is necessary to make the amount in the Priority Contract Account sufficient to pay Priority Contract Costs estimated to be due during the balance of such month and through the first five Business Days of the next succeeding calendar month. Amounts in the Priority Contract Account may be used solely to pay Priority Contract Costs.

Assuming the last series of Bonds are closed on October 10, 2002, the Department projects that approximately $366 million will be required to be deposited in the Priority Contract Account.

Operating Reserve Account

The "Operating Reserve Account Requirement" will be calculated, in respect of each Revenue Requirement Period, as the greater of (a) the largest aggregate amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any consecutive seven calendar months commencing in such Revenue Requirement Period and (b) either (i) 18 percent of the Department's projected annual Operating Expenses for any Revenue Requirement Period in which the Department is procuring all or a portion of the Residual Net Short and which commences prior to 2006, or (ii) 12 percent of the Department's projected annual Operating Expenses for any Revenue Requirement Period in which the Department is not procuring all or a portion of the Residual Net Short or which commences after 2005, provided, however, that solely for purposes of (b) above, for Revenue Requirement Periods commencing after 2003, the projected amount will not be less than the applicable percentage of Operating Expenses for the most recent 12-month period for which reasonably full and complete Operating Expense information is available, adjusted in accordance with the Indenture to the extent the Department no longer is financially responsible for any particular Power Supply Contract. All projections will be based on such assumptions as the Department deems to be appropriate after consultation with the Commission and, in the case of clause (i) above, may take into account a range of possible future outcomes.

The Operating Reserve Account is expected initially to be funded with a deposit of $777 million from amounts available in the Electric Power Fund at the time of issuance of the first series of Bonds.

In connection with the planned issuance of variable interest rate Power Supply Revenue Bonds, the Department expects to enter into agreements requiring the payment of Bond Related Costs on a parity with debt service on the Bonds, such as agreements with issuers of credit and liquidity facilities and agreements with interest rate swap providers.

Bond Charge Collection and Payment Accounts

The Bond Charge Collection Account will be initially funded with one month's estimated 2002 Bond Related Costs. The Bond Charge Payment Account will be initially funded with the sum of three months' estimated 2002 Bond Related Costs. In order to provide investors with comfort that the Department will be able to meet its debt service obligations, these funding levels will be required to be maintained at all times to provide what is referred to as "debt service coverage ."

All Bond Charge revenues will be deposited in the Bond Charge Collection Account. Subject to the prior claim on revenues in the Bond Charge Collection Account for the payment of costs under the Long-Term Priority Contracts, on or before the last Business Day of each month, the Department is required to transfer from the Bond Charge Collection Account to the Bond Charge Payment Account such amount as is necessary to make the amount in the Bond Charge Payment Account sufficient to pay Bond Related Costs (including debt service on the Bonds and all other Bond Related Costs) estimated to accrue or to be due and payable during the next succeeding three calendar months.

Initial deposits to the Bond Charge Collection Account and the Bond Charge Payment Account are projected to be $53 million and $158 million, respectively.

Debt Service Reserve Account

The "Debt Service Reserve Requirement" is an amount equal to maximum aggregate annual debt service on all outstanding Bonds, determined in accordance with the Indenture. The Debt Service Reserve Account is required by the Indenture to be funded in the amount of the Debt Service Reserve Requirement, initially with proceeds from the sale of the Bonds (or Alternate Debt Service Reserve Account Deposits referred to below, or a combination of both) and subsequently maintained and replenished, if necessary, from Power Charge Revenues or Bond Charge Revenues

For purposes of calculating the amount of the Debt Service Reserve Requirement from time to time, interest accruing on Variable Rate Bonds during any future period will be assumed to accrue at a rate equal to the greater of (a) 130 percent of the highest average interest rate on such Variable Rate Bonds in any calendar month during the twelve (12) calendar months ending with the month preceding the date of calculation, or such shorter period that such Variable Rate Bonds shall have been Outstanding, or (b) 4.0 percent.

Alternate Debt Service Reserve Account Deposits may be made to the Debt Service Reserve Account in lieu of cash and/or securities. Such Deposits may consist of irrevocable surety bonds, insurance policies, letters of credit or similar obligations. We are not currently assuming the use of Alternate Debt Service Reserve Account Deposits.

Upon the completion of the issuance of the Bonds, the Debt Service Reserve Account is expected to be cash funded with a deposit of $974 million from the proceeds of the Bonds.

Funding of Accounts at Bond Closing

At the time of the closing of the last of the series of Bonds, the bond and power-related accounts are expected to be funded at least at the levels described above. The Department's then current Electric Power Fund balance will be combined with proceeds of the bond issues to fund all accounts. The following is an indicative breakdown of account funding determined based on the assumption that the closing the sale of the last series of bonds occurs on October 10, 2002. It is important to note, however, that these projected levels of funding are still subject to final input bond insurers and commercial banks that will be providing credit enhancement and could change prior to the issuance of the Bonds.

Projected Sources and Uses of Funds
at Assumed 10-10-02 Final Bond Closing

Estimated Sources of Funds	**($ Millions)**
Principal amount of Bonds	$11,757
Original Issue Premium	92
DWR Electric Power Fund	2,037
Total Sources	$13,886
Estimated Uses of Funds	
Repayment of Interim Loan (including accrued interest)[1/]	$3,469
Repayment of State Loans (including accrued interest)	6,618
Deposit to Debt Service Reserve Account[2/]	974
Costs of issuance (including underwriters' discount)	118
Fees and expenses of providers of credit facilities and bond insurers	94
Deposit to Bond Charge Collection Account[3/]	53
Deposit to Bond Charge Payment Account[4/]	158
Deposit to Priority Contract Account[5/]	366
Deposit to Operating Account[6/]	1,260
Deposit to Operating Reserve Account[7/]	777
Total Uses	$13,886

[1/] Interest on the Interim Loan will be paid through September 30, 2002 and is not shown in this table.
[2/] Equals projected Maximum Annual Debt Service on all Bonds.
[3/] One month's estimated 2002 Bond Related Costs.
[4/] The sum of three months' estimated 2002 Bond Related Costs.
[5/] The next projected monthly amount due on Priority Long-Term Power Contracts.
[6/] The initial deposit is the amount required to be in the account when the last bond sale closes such that the minimum daily balance in the account is not projected to drop below the $1 billion target balance through 2002.
[7/] 18 percent of projected annual Operating Expenses for 2003.

Interest Rate Assumptions

The interest rate assumptions used in modeling the Department's projected debt service on fixed and variable rate Bonds to be issued were generated by JP Morgan, the senior managing underwriter for the Bonds, based on historical averages of bond indices and the best judgment of the firm's underwriting and sales professionals. The assumptions are as follows:

Estimated Composition of Bond Issuance

Debt Instrument	Amount/% of Total Amount/% of Total Debt		All-In Average Interest Rate
Tax-Exempt Fixed Rate Bonds	$5.676 billion	49%	5.76%
Taxable Fixed Rate Bonds	$1.090 billion	9%	6.96%
Tax-Exempt Variable Rate Bonds	$2.939 billion	25%	4.76%
Tax-Exempt Hedged Variable Rate Bonds	$2.051 billion	17%	5.33%
Total Bonds/Weighted Average Composite Rate	$11.757 billion	100%	5.38%

These projected interest rates are based on the assumption that the bonds are assigned "A" category ratings from a majority of the credit rating agencies.

Bond Maturity Schedules

The Summary of Material Terms contemplates that the Bonds will be amortized over 20 years, with the first principal payment being made to investors in 2004 and that principal and interest payments will be structured such that the aggregate debt service on all bonds is approximately equal in each year. The Addendum gives the Department modest flexibility in its amortization structure allowing for a variation of up to 5 percent from the lowest annual debt service to the highest.

Fixed and Variable Interest Rate Exposure

The Department plans to sell a significant portion (42 percent) of its bonds as variable rate instruments, as indicated in the table above. The rating agencies, however, will place a limit on the amount of variable rate exposure that the Department should have in its debt portfolio. Indications from the rating agencies are that this exposure should be limited to 25 percent. In order to comply with this limit, the Department expects to hedge a portion of its variable interest rate exposure by entering into floating-to-fixed payer interest rate swaps or by purchasing interest rate caps, as indicated in the table above. This hedging of variable rate risk results in what is referred to as a "synthetic" fixed rate for the Department. As is typical for interest rate swaps, the projected costs of the interest rate hedge are built in to the all-in average fixed interest rate shown in the table above.

Bond Insurance Costs

Bond insurance is projected to provide economic benefit to the Department significantly in excess of its cost. Therefore, the Department is seeking to obtain as much bond insurance from "AAA" rated insurers for the Bonds as it can secure at a reasonable cost. The amount of municipal bond insurance that will be available to the Department for the credit enhancement of the Bonds and the premiums associated with that insurance will largely be a function of the insurers' judgment of the strength of the credit being offered by the Department. The insurers are in the process of completing their own independent review of the credit but will also rely heavily on the credit ratings for the bonds issued by the rating agencies. The Department's current analysis reflects the amount of insurance capacity and the cost of insurance expected if "A" ratings are secured for the bonds from a majority of the rating agencies.

The Department estimates that initial credit enhancement costs will total $94 million.

Costs of Issuance

The costs of issuing the bonds that are to be paid from the proceeds of the Bonds include fees for professional services (legal, accounting, financial advisory, energy consulting, trustee, etc.) that have been incurred in the development of the Bond program. Given the lengthy process that has been required to complete this process, the total of these fees will be significant. In addition to the professional fees to be paid, the underwriting syndicate for the bonds, which includes more than 30 securities firms, will be paid underwriting fees for completing the sale or placement of the bonds.

The Department estimates that total costs of issuance will be approximately $118 million.

F. KEY UNCERTAINTIES IN THE REVENUE REQUIREMENT DETERMINATION

As mentioned earlier, a number of uncertainties facing the Department may require material changes to its Determination for the Second Revenue Requirement Period contained herein. These uncertainties are driven primarily by:

(1) Assumptions regarding participation in direct access programs;

(2) The Department's role in the procurement of net short, including residual net short for the IOUs;

(3) Developments with respect to the bond financing; and

(4) Potential changes in California electricity market design proposed by the CAISO.

Direct Access

In its February 2002 decision implementing the Department's Determination of Revenue Requirements, the Commission acknowledged that "the potential impacts of Direct Access customers' responsibility for a share of the Department's revenue allocation should be addressed on a timely basis" (California Public Utilities Commission, Decision 02-02-052 dated February 21, 2002, page 39). The Department is working with the Commission in analyzing potential approaches to the formulation of "direct access charges" on direct access customers that would minimize the shifting of additional power and bond costs to remaining Department customers.

For purposes of this Determination, no incremental participation in direct access, beyond that authorized by the Direct Access Order and the Department's revisions discussed in Section E, is contemplated. In the event legislation (AB 117 or other similar legislation) is enacted, this Determination has been developed based on the assumption the legislation will require the payment of direct access charges by all aggregation participants such that the Department is financially indifferent to their participation.

Transitional Issues Including Procurement of Residual Net Short

In accordance with the Act, the Department's purchase of net short energy requirements is intended to be an interim responsibility. The Act prohibits the Department from entering into new obligations to purchase energy after December 31, 2002. The Department and the Commission are working to transfer all of the Department's net short energy supply responsibilities to the IOUs as soon as practicable, including responsibilities for residual net short purchases and the management of the existing long-term energy contracts.

The Commission initiated a proceeding (Order Instituting Rulemaking 01-10-024) on October 25, 2001, to define the IOUs' responsibilities for net short energy procurement. In March 2002, the Department began plans to prepare for the transfer of the net short procurement from the Department to the IOUs. Under the Department's plan:

(1) Effective January 1, 2003, the IOUs will procure the residual net short energy and will schedule energy from the Department's power contracts to meet the hourly energy requirements of the Customers within their respective service territories; and

(2) The Department will continue to administer the Electric Power Fund to meet the Indenture and Bond covenants and monitor its revenue requirements, submitting new revenue requirement requests to the Commission as required under the Rate Agreement.

The Department plans to use the Commission's procurement process as the means to adopt the transition plan and is coordinating with the IOUs in planning for and implementing the transition. Despite the Department's plan however, it is expected that if all of the Department contracts cannot be fully assigned (for financial as well as management of output purposes), the Department will continue on an interim basis to assume financial responsibility, while the IOUs, who will operate under a management/operating agreement with the Department, will manage the output of contracts allocated to them for scheduling, dispatch, billing, and settlements.[37]

Any of the above cases for transfer of the net short to the IOUs presumes the prior creditworthy status of each of the IOUs. To the extent the IOUs are not creditworthy sufficiently in advance of January 1, 2003, either the Commission will need to find a means for the creditworthy IOUs to purchase on behalf of any non-creditworthy IOU, or new legislative or other legal authority to extend the Department's interim role of purchasing of the residual net short will be required. In such an event, it is expected that the Department's projection of retail revenue requirements over the revenue requirement period will change relative to what is contained in this Determination

Developments with Respect to the Financing

A principal assumption in the Department's determination of revenue requirements for the second revenue requirement period is the timing of bond issuance;

[37] The Department's plan contemplates that the transition will begin when the Commission orders the IOUs to accept the Department contracts and assume responsibility for procuring their residual net short. The Commission order will likely coincide with the judgment of creditworthiness of the IOUs by bond rating agencies. The procedure by which this is accomplished is the Commission's procurement process set out in the pending Order Instituting Rulemaking (OIR 01-10-024). The Commission President has established a proceeding schedule for the Commission decision and the subsequent order which would result in a final Commission decision on the net short energy procurement responsibilities of the IOUs by October 1, 2002, and the IOUs assuming responsibility for the full net short purchase or management thereof by no later than January 1, 2003. The completion of the full assignment of the Department contracts to the IOUs, such that the IOUs are responsible for the costs of contracts as part of each IOU's revenue requirement by January 1, 2003, is questionable. However, in the interim, the Commission could provide for a process in which the IOUs manage contract energy scheduling and purchases with continued uniform pro rata allocation of the costs until such time that the contracts can be fully assigned. Alternatively, some of the contracts, and their costs, could be assigned to the IOUs while a portion of the costs remain the financial responsibility of the Department until they can be assigned, and the Department revenue requirement attributable to such contracts can be shifted from the Department to the IOU assignee.

i.e., October of 2002. As mentioned in Sections B and E, the Department expects to retire its interim loan using the proceeds of the bond issuance. The Department has not included in its revised estimate of revenue requirements for either the First Revenue Requirement Period or the Second Revenue Requirement Period, the debt service costs associated with the Interim Loan. If bonds are not issued by the end of October 2002, the Department will be required to make an Interim Loan principal payment of approximately $385 million on October 31, 2002. Neither the October 31, 2002 principal payment or a $51 million interest payment due on September 30, 2002 were included in the Department's filing covering the First Revenue Requirement Period. Therefore, any delay in the issuance of bonds could result in a significant increase in the revenue requirement for 2002.

A prolonged delay in bond issuance will have a material impact on the Department's revenue requirement for the Second Revenue Requirement Period as well. The Debt Service on the Interim Loan for calendar year 2003 would be $1.691 billion. The Bond Charge Revenue Requirement required to meet the debt service on a $11.75 billion bond issuance is expected to be $1.140 billion. Therefore, an additional $551 million, the debt service on the Interim Loan and the expected bond issuance, would need to be collected through the revenue requirement for calendar year 2003.

Proposed Changes to the California Electricity Marketplace

Finally, proposed changes to the California electricity market may influence the Department's determination of revenue requirements for both the First and Second Revenue Requirement Periods. The CAISO is undergoing a process of redesign for the operation of the transmission system and the movement of bulk (wholesale) power in California. The redesign, called Market Design 2002 ("MD02"), is being carried out in response to orders issued by FERC. The FERC Order on Clarification and Rehearing of December 19, 2001 directed the CAISO to file its revised congestion management proposal and a plan for implementation of a day-ahead market. In addition, the CAISO is responding to the impending expiration on September 30, 2002 of the market monitoring and mitigation program instituted by FERC in its June 19, 2001 Order on Rehearing of Monitoring and Mitigation Plan.

The CAISO introduced its new market design proposals through a Preliminary Report on Project Approach and Key Market Design Elements Under Consideration on December 21, 2001. The Preliminary Draft Comprehensive Design Proposal was released on January 8, 2002, followed by a series of technical workshops. Since then, the CAISO has received comments, made additional presentations, including to the CAISO Board, and developed its comprehensive market design proposal. In addition, the CAISO has determined that certain elements of the comprehensive market design can be postponed while others must be in place by October 1, 2002, when FERC's western energy markets mitigation plan expires.

MD02 consists of ten parts:

(1) Available Capacity ("ACAP") Obligation. Load-serving entities will face an obligation to maintain an ACAP, defined as a percentage margin above

their monthly peak load, through a combination of their own generation, firm energy contracts, capacity contracts, and demand-side management.

(2) Forward Congestion Management ("CM"). The CAISO proposes to use a full network model to adjust schedules to clear congestion.

(3) Firm Transmission Rights ("FTRs"). Redesign of CM requires redesign of FTRs.

(4) Forward Day-Ahead Spot Energy Market. The Day-Ahead market will perform energy trades within the CM procedures.

(5) Residual Forward Unit Commitment. After the close of the day-ahead market, the CAISO will determine whether there is a need for additional generation resources to be brought on-line for the next day's needs.

(6) Ancillary Services. Bidders will be required to submit a single energy curve for all services offered by a particular resource. Currently, different energy curves may be submitted for each ancillary service for which a resource is qualified.

(7) Modification to the Hour-Ahead Market. The Hour-Ahead market will be simplified by performing only CM and energy trading.

(8) Real-time Economic Dispatch Using a Full Network Model. This will be a 10-minute dispatch that will take into account inter- and intra-zonal congestion, resulting in nodal real-time prices.

(9) Real-time Bid Mitigation for Locational Needs. This will reduce local market power.

(10) Damage Control Price Cap on CAISO Markets. Beginning October 1, 2002, and continuing until market conditions are competitive enough to support a higher price cap, the CAISO proposes to set the price cap at three times the estimated variable cost of a gas-fired generating unit with an incremental heat rate of 20,000 BTU or $250 per MWh, whichever is greater.

On May 1, 2002, the CAISO made a comprehensive filing to FERC consisting of specific tariff language proposed to go into effect on October 1, 2002, coincident with the end of the FERC mitigation plan. In addition, the filing contains language describing the comprehensive market design proposed to be implemented over time, with specific tariff language to be supplied in a filing in mid-June 2002.

The CAISO released Draft October First Design Elements on March 27, and released proposed tariff language for the October First Design Elements on April 19. The elements proposed for October 1, 2002, are simplified from the comprehensive market design and represent the first phase of the CAISO's efforts to implement the above changes. The changes proposed for October 1, 2002, include the following eight elements.

(1) Must-Offer Obligation. This is similar to the current must-offer obligation under the FERC's western mitigation system.

(2) Residual Unit Commitment ("RUC"). This will be similar to the RUC system proposed in the comprehensive design, with the exception that the October 1, 2002, version allows for competition between intertie energy bids and internal units.

(3) Changes to Day-Ahead and Hour-Ahead Markets. Bidders will submit a single bid for all energy and ancillary services.

(4) Damage Control Bid Cap. This will be a single cap for all energy and ancillary services.

(5) Bid Screens and Mitigation. There will be individual resource bid screens to mitigate bids that exceed explicit threshold limits and have a material effect on projected market-clearing prices.

(6) 12-Month Market Competitiveness Index and Pre-authorized Additional Mitigation Provisions. This is to be an explicit measure of the competitiveness of the market to determine if or when the market should be declared unjust and unreasonable.

(7) Other Market Power Mitigation Measures. This will include local market power mitigation measures and penalties for failure to honor binding real-time bids.

(8) Transitional Available Capacity Obligation. Because the ACAP is not likely to be feasible by the beginning of October 2002, the CAISO proposes a monthly assessment process to take account of all available resources, including DWR power contracts, and will identify a potential shortfall early enough to enable load-serving entities and other responsible parties to procure additional supply.

Until such time as the CAISO has gone through its market design process, and FERC has acted, it is difficult to determine which of the modifications proposed by the CAISO will be adopted, if any. The uncertainty of the ultimate decisions has precluded any modeling of the possible effects of such market restructuring on the net short energy requirements and their costs, or the cost of energy in the spot market in the future. The Department intends to continue monitoring the California market restructuring efforts. If there are material changes to the market, the Department will evaluate the effects of such changes. If the changes are expected to have a material effect on the Department's net short energy purchases and resultant revenue requirement, the Department would notify the Commission and, if necessary, modify the Department's revenue requirement accordingly.

G. JUST AND REASONABLE DETERMINATION

This section explains the Department's reasons for determining that the revenue requirement is just and reasonable.

Background

An understanding of the circumstances under which the Department developed and administered the power supply program is necessary to understand the Department's revenue requirement and its just and reasonable determination.

Wholesale electricity prices skyrocketed to exorbitant levels in mid- to late 2000. The price increases have been attributed in varying degree to the dysfunctional market that resulted from deregulation, to supply shortages and to various forms of outright manipulation of both supply and demand. The prices caused financial distress for the investor-owned utilities ("IOUs"). Faced with the threat of IOU insolvency, wholesalers began to doubt the creditworthiness of the IOUs, and some refused to sell into the California market. The power supply for millions of Californians was in jeopardy, blackouts loomed, and the electric system was on the verge of collapse.

To alleviate the crisis, Governor Davis proclaimed a state of emergency on January 17, 2001, and ordered the Department to immediately purchase and sell electric power, as necessary, to mitigate the effects of the emergency. After an initial, temporary grant of authority in SB7X, the Legislature passed AB1X granting the Department the authority to purchase and sell electricity and finance the costs with revenue bonds. Advances from the State's General Fund financed the initial costs of the program. Continued reliance on the General Fund might have threatened financial instability for the State as a whole.

AB1X (also herein called "the Act") thrust the Department into a role never before undertaken by any state agency in California. The Department was directed to procure electricity to meet the needs of consumers in the three investor-owned utility service areas. The Department's legal authority and legislative direction for this undertaking are found in AB1X. The purpose of the emergency legislation was described by the Act as follows:

> The furnishing of reliable reasonably priced electric service is essential for the safety, health, and well-being of the people of California. A number of factors have resulted in a rapid, unforeseen shortage of electric power and energy available in the state and rapid and substantial increases in wholesale energy costs and retail energy rates, with statewide impact, to such a degree that it constitutes an immediate peril to the health, safety, life and property of the inhabitants of the state, and the public interest, welfare, convenience and necessity require the state to participate in markets for the purchase and sale of power and energy.[38]

[38] California Water Code Section 80000.

The Act authorizes the Department to contract for the purchase of power "on such terms and for such periods as the department determines and at such prices the department deems appropriate" taking into account the following factors:

(1) The intent of the program is to achieve an overall portfolio of contracts for energy resulting in reliable service at the lowest possible price per kilowatt-hour.

(2) The need to have contract supplies to fit each aspect of the overall energy load profile.

(3) The desire to secure as much low-cost power as possible under contract.

(4) The duration and timing of contracts made available from sellers.

(5) The length of time sellers of electricity offer to sell such electricity.

(6) The desire to secure as much firm and nonfirm renewable energy as possible.[39]

The Legislature in AB1X thus provided guidance and direction for the power supply program. The Department has implemented the program under the authority of AB1X and in accordance with the purposes, express authorities and limitations, and guidance contained therein.

Financing for this new power supply program is also governed by AB1X, as amended. Most fundamentally, all obligations authorized by the Act are payable solely from the Electric Power Fund. The Electric Power Fund consists of revenues received from the program's activities, proceeds from the Interim Loan, proceeds from future bond sales, and an advance from the General Fund which must be repaid. Neither the full faith and credit nor the taxing power of the state are pledged for any payment under any obligation arising from the Department's activities pursuant to the power purchase program.[40]

As a public agency, the Department may not realize a profit from the power supply program. This is recognized in the Act's provisions that require all revenues to be deposited in the Electric Power Fund, limit the use of amounts in the Electric Power Fund to the purposes of the Act and prohibit sale of power at costs greater than the its aggregate costs under the Act.[41] The power supply program is a cost-recovery program: it operates on a not-for-profit basis and must recover all costs of the program in its revenue requirements.

The components of each revenue requirement are defined in Section 80134(a), which provides that the Department shall, at least annually, and more frequently as required, establish and revise revenue requirements sufficient, together with any

[39] California Water Code Section 80100.
[40] California Water Code Section 80200(d).
[41] California Water Code Sections 80200(a), 80200(b), and 80116.

moneys on deposit in the fund, to provide all of the following: (1) debt service on all of the bonds issued under the Act, (2) the amounts necessary to pay for power, including the cost of electric power and transmission, scheduling, and other related expenses, and to make payments under any other contracts, agreements, or obligations entered into by it pursuant to the Act, (3) reserves in such amount as may be determined by the Department from time to time to be necessary or desirable, (4) interest on the General Fund advances, (5) repayment of the General Fund advances, and (6) the administrative costs of the Department incurred in administering the Act.

Under the Rate Agreement, each revenue requirement is to be submitted to the California Public Utilities Commission ("the Commission") for the calculation and imposition of Department charges.

The Commission is the agency which holds the authority to determine whether an IOU's proposed charges are just and reasonable under Section 451 of the Public Utilities Code. Such matters are frequently the subject of Commission proceedings and orders, and the Commission regularly issues decisions on whether particular IOU costs or expenses are "just and reasonable" under various circumstances, i.e., whether it is just and reasonable to permit them to be either included in an IOU's "rate base" or deducted from revenues derived from rates in order to determine whether net revenues result in a reasonable rate of return for the IOU on its rate base. A common theme of many of these decisions is that in order to be "just and reasonable" the costs or expenses must be those a "prudent person" would incur to provide the commodity or service being provided by the IOU given the circumstances and facts that were known or should have been known at the time the cost or expenses to provide the commodity or service were incurred.

Under AB1X, however, authority to make any just and reasonable determination with respect to the power supply program is expressly conferred upon the Department. Section 80110 states that "any just and reasonable review under Section 451 [of the California Public Utilities Code] shall be conducted and determined by the department." The Rate Agreement interprets that provision by providing that the Department has the obligation to "conduct whatever procedures are required by law to determine that [each cost included in the Retail Revenue Requirement] is just and reasonable within the meaning of Section 451 of the California Public Utilities Code."

The Meaning of "Just and Reasonable" for the Power Supply Program

Given the Legislature's express reservation to the Department of the right to make any just and reasonable determination with respect to its revenue requirement, the first level of inquiry must be what such a determination means in the context of the power supply program as authorized in AB1X. This may also be described as defining what <u>standard</u> the Department should use in making a just and reasonable determination. (A just and reasonable determination also raises questions about what <u>process</u> will be used, and that issue is discussed separately below.)

Three approaches have been identified as possible ways to define the standard by which the Department makes the just and reasonable determination. The three are described here in order to disclose the Department's analysis of AB1X and because it will be helpful to understanding the Department's determination.

First, it is possible that the Legislature did not intend to require that a just and reasonable review be conducted. Because AB1X uses the word "any" before "just and reasonable review," the Legislature might have contemplated that no review be conducted. Alternatively, it could be interpreted that the Legislature intended that the Department decide whether such a review was warranted, that the Legislature left it to be decided in the implementation of the program by the Department, or that the just and reasonable determination with respect to each cost be the determination to incur that cost in furtherance of the public purposes of the Power Supply Program.

Second, the intent of AB1X could be that the Department conduct an after the fact review and apply the same standard that is applied by the Commission to IOU's under Section 451 of the Public Utilities Code (hereinafter "Section 451.") This approach is initially appealing in its simplicity; however, in its application a number of difficulties arise. First, Section 451 itself provides no definition of "just and reasonable" and it has not been defined by a Commission regulation. Second, the Commission has no ready-made precedents available to determine how a just and reasonable determination would be made in the context of a not-for-profit public agency acting as a purchaser. The inquiry at the Commission always involves for-profit entities, and the determination of just and reasonable ultimately involves decisions regarding the appropriate rate of return on the investors' investment (the rate base). These facts do not apply to the Department's revenue requirement because by law the Department is not permitted to realize a profit from its activities, nor does it have any shareholder capital from which to pay for costs that cannot be included in its rates or charges. In fact, any just and reasonable review and determination must be consistent with the mandate of Section 80134 that the Department establish and revise revenue requirements sufficient, together with other moneys, to provide for all of the Department's costs. These distinctions are so fundamental that Commission decisions on just and reasonable determination are unlikely to provide definitive guidance.

To the extent that many of the Commission decisions rely on a "prudent person" standard – that is, whether the costs would have been incurred by a prudent person under the circumstances existing at the time the decision to incur the costs was made – the revenue requirement could be analyzed under that standard. In essence, such a review would require the Department management to engage in a critical evaluation of the program with an eye to determining whether it in fact it meets the standard of a prudent person. The Department considers this type of review to be an ongoing responsibility of its managers, in all programs, and in fact is a fundamental tenet of public administration. A review of the revenue requirement under the prudent person standard could be similarly conducted.

The third approach to defining the meaning of "just and reasonable" focuses on AB1X as the source of legal authorization for the power supply program, and as such, the primary source of guidance for the Department's implementation of the program. The statute's statement of purpose, the list of factors for the power purchase contracts, and the full-cost-recovery financing system set the framework for defining whether the revenue requirement is "just and reasonable." In many respects, this approach is the same as the second approach, but much more explicitly takes into account the Department's nature as a public agency, the specific program mandates of the Act and the financial structure of the Electric Power Fund as specified by the Act, all of which define "the circumstances under which each decision is made." This approach was adopted in the regulations promulgated by the Department (Section 517) as discussed below.[42]

The California Administrative Procedure Act

Background

The California Administrative Procedure Act (APA) (Gov. Code sec. 11340, *et. seq.*) requires that a state agency must satisfy minimum basic procedural requirements, including notice and opportunity for public comment, before adopting any administrative "regulation." Stated alternatively, the APA applies to the exercise of any "quasi-legislative" power conferred by statute. (Gov. Code sec. 11346(a).) For APA purposes, a "regulation" is defined as any rule of general application that implements, interprets, or makes specific the law enforced or administered by the agency. A rule of general application is one that applies to an open class. (*Tidewater Marine Western, Inc. v. Bradshaw* (1996) 14 Cal.4th 557, 570-571, 59 Cal.Rptr.2d 186, Gov. Code sec. 11342.600.) Generally, a "quasi-legislative" action involves the formulation of general rules to be applied in future situations that arise under them.[43]

PG&E brought a lawsuit in 2001 and alleged that each time the Department makes a just and reasonable determination, it is a regulation subject to the APA. The Department opposed the lawsuit. The Superior Court eventually ruled that Section 80110 of the Act "triggers the protection of the California Administrative Procedure Act," and ordered the Department "to follow the procedures mandated by the California Administrative Procedures [sic] Act before making any determination whether DWR's revenue requirements are just and reasonable." To comply with the court's order, the Department has promulgated emergency regulations to specify the applicable standard and procedure for making just and reasonable determinations under AB1X. The Department has also filed a notice of appeal.[44]

PG&E continues to assert that each revenue requirement itself must be adopted as a regulation. PG&E and the Department both submitted letters to the judge in the

[42] As a result, the regulations are consistent with Public Utilities Code Section 451.

[43] *20th Century Ins. Co. v. Garamendi* (1994) 8 Cal.4th 216, 275, 32 Cal.Rptr.2d 807.

[44] The Department contends that the determination of its revenue requirement, and the determination that the revenue requirement is "just and reasonable," *are not* subject to the APA because they are essential steps in a ratemaking action. (Gov. Code § 11340.9(g); *Winzler & Kelly v. Department of Industrial Relations* (1981) 121 Cal.App.3d 120, 174 Cal.Rptr. 744.) Without the determination by the Department, there would be no charges imposed by the Commission to recover the Department's revenue requirement. "Ratemaking" actions by the Commission are expressly exempted from the APA by Government Code sections 11340.9(g) and 11351. Thus, the exemption established by Government Code section 11340.9(g) extends to the Department's determinations regarding its revenue requirement under AB1X. Alternatively, the Department contends that the APA does not apply because the determination of the revenue requirement and the determination that the revenue requirement is just and reasonable are one-time decisions, not general rules intended to be applied to future situations, and because a determination that a revenue requirement is "just and reasonable" is an application of an existing rule (the "just and reasonable" standard) to existing facts.

Superior Court case on this very point, and ultimately the judge declined to issue the judgment in a form supportive of PG&E's position, and issued the judgment in a manner that leaves the method of APA compliance to the Department in the first instance.

In accordance with the discretion afforded to administrative agencies by law and recognized by the Superior Court, the Department thereafter proceeded to evaluate what type of regulation was required in order to comply with the court's ruling that the APA applies to the just and reasonable determination.

The Topics Addressed in Regulations

Prior to developing regulations to comply with the court's order, the Department reviewed its AB1X related policies and procedures with regard to APA procedural requirements. Three major areas were considered: (1) the establishment of the periodic revenue requirement, (2) the application of the standard for "just and reasonable" in the AB1X context; and (3) the creation of a process for public participation in the Department's just and reasonable determinations.[45] Upon the completion of this assessment, the Department decided to move forward with emergency regulations in areas (2) and (3). Those regulations are now in effect (see 23 Calif. Code Reg. Sections 510-517) and have been applied by the Department in making this determination.

After carefully considering what is covered by, and exempted from the APA, the Department decided that the establishment of the periodic revenue requirement is not required to be treated as the adoption of a regulation.

Essentially, an individual revenue requirement, even if not exempt as a part of a ratemaking action, involves the aggregation of *specific facts* for a *specific period of time*. These facts (actually determinations concerning specific costs and cost projections) represent a single snapshot of the costs of the program for a particular period of time. The costs for one period do not repeat themselves in a subsequent period. Cost projections, however, may be revised ("trued up") in subsequent periods as actual cost information becomes available. Once the Department has established the amount of a revenue requirement for a period, the Commission acts to establish the charges that the various end-use customers pay for the power they purchased during the period. For these reasons, the Department decided that each periodic establishment of a revenue requirement is a one-time activity which does not meet the statutory definition of a "regulation."[46] It does not establish a rule of general application.[47]

[45] The Department's internal management processes are exempt from the APA pursuant to Government Code Section 11340.9(d).

[46] In reviewing regulations adopted by other state agencies, the Department was unable to identify any other instance in which any state agency had adopted its total revenue needs for a period of time as a regulation. There are, however, numerous instances, particularly with regard to the licensing of businesses and professions, where a statute provides that a state agency is to fully fund some activity (like an examination) through the setting of a fee which is to be paid by those who take the examination. To set the fee, the agencies must identify all the costs that are attributable to the activity and divide that amount by the number of persons projected to take the examination. The agency then may adopt a regulation to set the examination fee. The costs attributable to the examination and the projected number of examinees are not adopted as regulations because the costs and the projected number of examinees are facts relied upon to set the amount of the fee regulation, not rules of general application. This is similar to what happens under AB1X. The power supply program administered by the Department is to be fully paid for by the end-use consumers of the power. To accomplish

The Emergency Regulations

The Department developed regulations to establish procedures for public participation in the Department's determination of its revenue requirement and to interpret and make specific the "just and reasonable" standard in the context of the AB1X power supply program. The regulations were submitted to the California Water Commission[48] for its review and approval and then submitted to the Office of Administrative Law (OAL) for review.[49] The Department gave notice of the California Water Commission meeting to consider the proposed regulations ten days prior to the meeting. Notice was given both to the traditional list used for Water Commission meetings as well as the service list in the Commission's Rate Stabilization docket (Application 00-11-038 et al.). The purpose of the expanded notice was to assure that interested parties in the energy field would get notice of the proposed regulations.

The Water Commission held a public meeting on June 7, 2002, at which it heard a staff briefing on the regulations, asked questions about the regulations, solicited public comment, and ultimately approved the regulations. After approval of the regulations by the commission, OAL reviewed the proposed regulations to assure they met the statutory standards in Government Code Section 11349.1: Necessity, Authority, Clarity, Consistency, Reference, and Nonduplication. OAL approved the regulations and filed them with the Secretary of State, at which time they became effective.

Public Participation in the Current Determination

In accordance with the procedures established by the regulations, the Department gave notice of its proposed determination on June 14, 2002, and sent the announcement to all persons on the service list. The notice set July 5 as the deadline for receipt of public comment. On June 14, 2002, the Department issued a <u>Proposed Determination of Revenue Requirements For the Period January 1, 2003 Through December 31, 2003 With Reexamination and Redetermination For the Period January 17, 2001 Through December 31, 2002</u>.

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this, the Department identifies all the costs and projected costs attributable to the program for a particular period (a revenue requirement). The Commission then sets the rate the consumers must pay for the power they used. As this analogy demonstrates, the charges the consumers must pay, not the underlying costs and projected costs, are the rules of general application that would be subject to the APA, but for the applicable exemptions. The costs and projected costs are the facts relied upon to set the amount the consumers must pay pursuant to the regulation.

[47] As described above, the Department also contends that the revenue requirement is an essential part of a ratemaking process, and is exempt from the APA pursuant to the "rates, prices, and tariffs" exemption established by Government Code section 11340.9(g).

[48] Water Code Section 160 requires that the Department's regulations be approved by the California Water Commission. The Water Commission is a public body independent of the Department of Water Resources whose administrative functions have traditionally been provided by the Department. The Commission has nine members appointed by the Governor and approved by the Senate. Meetings of the Commission are public and subject to the Bagley-Keene Open Meetings Act (Government Code § 11120).

[49] As indicated above, it is the Department's position that the determination of a revenue requirement and the determination that a revenue requirement is "just and reasonable" *are not* subject to the APA. Even though the Department contends these regulations are exempt from the Administrative Procedure Act, the Department chose to adopt them as emergency regulations using Administrative Procedure Act procedures in order to comply with the Superior Court order while appealing it, and in order to provide the public with a meaningful opportunity for public participation in the development of the regulations through the use of familiar procedures and to reduce the possibility of additional litigation. (See *20th Century Ins. Co. v. Garamendi* (1994) 8 Cal. 4th 216, 248 and 270-271.) Accordingly, the Department submitted the emergency regulations to OAL for review pursuant to Government Code section 11349.6.

The Proposed Determination was provided to the persons or entities that provided comments or requested notice of the prior determination dated November 5, 2001, and any other persons or entities requesting notice of this current revenue requirement determination. A copy of the Department's Proposed Determination was posted on its website, http://www.water.ca.gov. For those persons or entities executing Non-Disclosure Agreements, the Department provided two CD's containing the detailed information upon which the Proposed Determination was made. The initial deadline for submitting comments on the Proposed Determination was July 5, 2002.

To facilitate an understanding of the Determination and to provide immediate response to initial questions, the Department held a workshop in Sacramento on June 19 to review its Proposed Determination with interested parties. Announcement of this meeting was provided with the material distributed on June 14, 2002 and was included in the Department's web site posting. The workshop was conducted by those key personnel and consultants representing the Department who are intimately involved in the development of the Proposed Determination and in the issuance of the planned bond financing. The workshop attendees included representatives from PG&E, SCE, SDG&E, a media representative from "Electric Power Daily," and individual members of the public. The Department also sponsored a series of three conference calls with interested parties, which were held on July 1 through 3, 2002. The calls each lasted about one hour, and were ended with the mutual concurrence of the participants. Participation on these calls included representatives from PG&E, SCE, and the California Large Energy Consumers Association, among others. A broad spectrum of topics were covered but significant emphasis was placed on bond financing issues, load forecasting, direct access, self-generation, handling of bi-lateral contracts, and ancillary services.

In response to comments and questions raised during the public comment process, the Department determined that it would rely on additional material in making the determination. Pursuant to the California Code of Regulations Title 23, Section 513, the Department noticed Significant Additional Material on July 3, 2002. On July 8, 2002 the Department sponsored a fourth conference call with interested parties to advise of the planned notice, respond to comments, and to announce that additional information would be provided and that the period for review and comment would be extended. On July 9, 2002 the Department released a Notice of Significant Additional Material to the Commission service list A.00-11-038 as well as to those persons that had requested notice under the APA procedures. The Department also posted the release on the Department's web site. The release included the Notice, Testimony Submitted in the CPUC Application 00-11-038 (Bond Charge Phase) and an index of 52 documents relied upon and available for review upon request. The documents were subsequently provided to the three IOU's. Written comments on the additional material were due on July 16, 2002. Comments were received from PG&E, SCE, SDG&E, California Large Energy Consumers Association, Counsel for Energy Producers and Users Coalition, Goodrich Aerostructures, Inc., Kimberly Clark Corporation, and an individual member of the public.

Subsequently, the Department identified further Significant Additional Material which was released on July 26, 2002, to the same service list as noted above. This information included the transcript of the interim loan obtained by the Department on June 26, 2001, and a brief description of an interim model in use prior to ProSym, which was used in evaluating alternative contract proposals and estimating residual net short energy needs. For those parties with non-disclosure agreements, a copy of a CD containing the model was available upon request. Concurrent with this release, the comment period was extended to August 5, 2002. On August 9, 2002, another Notice of Significant Additional Material was released and the comment period was extended to August 14, 2002. On August 13, 2002, the Department also provided an updated copy of its Prepared Testimony concerning Bond Related Costs previously submitted to the Commission in the Commission's Rate Stabilization docket. Although SCE and PG&E noted in their August 14 comments that there was inadequate time for review, the Department maintains that it has provided sufficient opportunity to comment on its materials. Given that the information provided on August 9 and August 13 consisted of statements of facts, historical background, and updates to previously released information, the time frame allotted was adequate under the circumstances. Furthermore, in order to provide the Commission with sufficient time to implement the Department's 2003 revenue requirements, closing the comment period on August 14, 2002 was reasonable in light of the previous extensions granted by the Department.

During the entire process, the Department has reviewed all comments received and assessed whether a change in the revenue requirement is warranted, and whether such change would materially impact on the revenue requirement. To the extent changes were necessary, they have been incorporated in the Final Determination. This is amply demonstrated by new information provided in the comments that has led to a new update to the ProSym data and the Revenue Requirement. On August 9, 2002, the Department provided a listing of changes to the Proposed Determination. Those parties that have executed a non-disclosure agreement also received revised CD's updating ProSym and Revenue Requirement model data. The comment period was extended to August 14, 2002.

Criticisms of the Process

DWR has received comments that the process used pursuant to the regulations is inadequate. These comments state that:

> DWR is proposing to determine the "reasonableness" of its revenue requirements and costs without evidentiary hearings, without formal discovery, without an opportunity for cross-examination of its personnel or its supporting documentation, without complying with other "due process" requirements of the California Administrative Procedure Act, and with a single round of comments from the public after only 32 days prior notice. (PG&E's Preliminary Comments)

The Department is following the process defined in the emergency regulations. Notably, no criticisms of the regulations were made during the opportunity for public comment at the Water Commission or to the OAL. Nevertheless, the Department recognizes that this current determination represents the first time the regulations have been applied and that there may be some confusion about the process. For that reason, the Department has made many efforts to assure that all interested parties have the information on which the determination is based and that they have an opportunity to comment. The comment period has been extended several times to ensure that all interested parties have a meaningful opportunity to submit comments. Comments which do not comply with the regulations have nevertheless been considered based on their content rather than being rejected for technical deficiencies.[50]

The comments submitted that are critical of the public participation process seem to be based on a belief that the process should be a full-fledged evidentiary hearing similar to the process conducted by the Commission. As discussed above, however, the role of the Department under AB1X and the nature of a not-for-profit cost-recovery system make many of the procedures used by the Commission in its decisionmaking unnecessary. The Commission is an agency that has authority over private companies and therefore different concerns are present. Nothing in AB1X makes Commission procedures applicable to proceedings conducted by the Department.[51]

The Department will be complying with the APA to convert the emergency regulations to permanent regulations within the time limits set forth in AB1X and the APA. This will again provide an opportunity to receive comments on the public participation process and will allow the Department to revise the process if appropriate. The Department will encourage comments on the process in this next phase. In addition, the Department will independently review and evaluate how the existing process functioned with respect to this current determination and revise the regulations to be proposed as permanent regulations as appropriate.

In the face of the criticisms of the current emergency regulations' process for public participation, the Department has considered whether to postpone the revenue requirement determination until the permanent regulations are in place. This decision requires weighing the need for timeliness in making the revenue requirement determination and submitting it to the Commission against the benefits obtained from an enhanced public review process. In making this decision, the Department has considered the comments submitted that are critical of the process, the functioning of the process in this determination itself, the efforts made to promote public participation in excess of that required by the emergency regulations, the nature and substance of the comments on the revenue requirement and just and reasonable determination

[50] Many comments lacked a statement verifying factual assertions which is required by Title 23, Section 512(e)(2). Commenters were requested to provide such a statement. Other deficiencies such as a failure to correctly label the comment were waived.

[51] Further, the Department shares the view reflected in Commission decisions that the constitutional due process right to a trial type hearing is limited to those quasi-judicial proceedings in which a party has a vested property interest at stake. See, for example, *Re Competition for Local Exchange Service* D. 95-09-121, 61 CPUC2d 59. Under AB1X there is no direct relationship between IOU return on investment and the Department's determination of its revenue requirement. Under AB1X, the IOUs are in a contractual relationship with the Department to deliver the power purchased by the Department to the end-use consumers and to collect and transmit to the Department the money owed by the consumers to the Department. (In PG&E's case, the servicing obligation arises from an order entered by the Commission after hearing.) The IOUs are paid for performing these services under the terms negotiated in the contracts, or pursuant to the Commission's order. In addition, the Rate Agreement expressly provides that the Department charges shall be established without regard to the levels or amounts of any particular rates or charges authorized by the Commission to be charged by an IOU for electrical power sold by such IOU. Thus, the IOUs have no vested property interest in the Department's revenue requirement and its "just and reasonable" determination.

(comments were extensive), the time extensions that were made to permit additional comments, the additional workshops and conference calls made available, and the widespread notice that was given for the emergency regulations and the proposed determination. The Department also considered the fact that any delay will further delay and potentially impair the Department's ability to proceed with the bond sale, repay the Interim Loan and reimburse the General Fund. The Department also considered that each revenue requirement contains a true-up of prior revenue requirements, so that each change based on new information is incorporated into the next revenue requirement. Based on these considerations, the Department decided not to postpone the revenue requirement and its just and reasonable determination due to criticisms of the public participation process. Any valid criticisms of the process will be addressed in the conversion of the emergency regulations to permanent regulations, and any revisions to the revenue requirement determination arising out of a new public participation process will be incorporated into the next revenue requirement.

The Revenue Requirement Is Just And Reasonable

Approach

In addition to considering the facts, legal authorities and constraints, and circumstances described in the record and summarized above, the following principles were used in the just and reasonable review.

(1) The standards for "just and reasonable" to be applied will be both the standard defined in the emergency regulation,[52] and a "prudent person" standard. Both interpretations of the appropriate standard for just and reasonable will be used, although by law only the standard stated in the regulations governs such review. This two-pronged approach is for the purpose of assuring a comprehensive review, providing increased information to the public, and permitting Department management to evaluate the power supply program. In addition, use of the prudent person standard will provide a record for judicial review should the emergency regulations be challenged and a different standard imposed.

(2) The just and reasonable determination is based on the entire record disclosed in the public review process, including confidential documents, and not solely on the statements made or documents referenced in this Determination. Failure to specifically reference, in this Determination, materials in the record should not be interpreted to mean that the Department did not rely on those materials and incorporate such review in issuing this Determination.

[52] 23 Calif. Code Regs. Section 517.

The Individual Components of the Revenue Requirement Are Just and Reasonable

Long-Term Power Purchase Contracts

The long-term power purchase contracts entered into by the Department under the authority of AB1X are the centerpiece of the power supply program and were critical to halting the downward-spiraling emergency circumstances existing in mid-January, 2001. In the context of that emergency, and given the Legislature's objectives, the long-term power purchase contracts constitute a just and reasonable component of the revenue requirement.

<u>Market Conditions and Achievement of Objectives</u>

The volatile and dysfunctional market conditions existing in mid-January 2001 are well documented in the record and earlier in this Determination. The Legislature intended that the Department's power supply program achieve an overall portfolio of contracts for energy resulting in *reliable service at the lowest possible price.* The Department's objectives were to meet this two-part directive: reliability and cost-effectiveness.

Immediately prior to the time the Department commenced its power supply program, nearly all purchases of energy by the IOU's to meet the net short were from the spot market. Average wholesale power costs had reached an unprecedented 32 cents/kWh in January of 2001, approximately ten times the price of one year earlier. It was widely recognized that reducing reliance on spot markets was necessary to normalize the spot market prices. In addition, as explained in the record (Nichols declaration), the almost exclusive use of the spot market to meet the net short was resulting in power shortages. To increase the supply reliability, a decreased reliance on the spot market was necessary.

Accordingly, the Department's core strategy was to emphasize longer-term contracts as a means to secure new generation capacity for greater reliability and long-term price stability. This strategy underwent periodic review and modification as the program progressed and market conditions changed. The long-term power purchase contracts must be assessed based on whether they contributed to the achievement of the goal of increased reliability at lower price, by shifting supply from the spot market to a long-term supply.[53]

<u>Portfolio Planning</u>

The Department undertook immediate and repeated efforts to estimate, and periodically refine and verify the net short energy requirements that the Department

[53] In addition, under the bond security and cash flow structure designed in the spring of 2001 and represented by the proposed rate agreement considered by the Commission at its October 2, 2001 meeting, a supply of power for the Department to sell would be necessary during the entire term of the bonds, originally planned to be 15 years, if other sources of revenue could not ultimately be developed.

was responsible for procuring.[54] Portfolio planning was prepared in coordination with those estimates to assure that the energy procured be appropriate in terms of quantity and overall portfolio design. The Department's net short estimate that was used as the basis for determining the amounts of energy to place under long-term contract required a detailed set of assumptions and analyses regarding total energy demands of customers in the IOU service areas, the effects of energy conservation, the amount of direct access obtained by such customers, the performance of the IOUs' owned generation, the performance of QF contract suppliers, and the status of the IOUs' other bilateral contracts. This net short calculation was updated at least every two weeks as conditions changed and as more information became available.

The goals for the portfolio were in furtherance of the Act. Specifically, the Department intended that the portfolio of long-term contracts (a) provide an energy supply to match the expected quantity of net short energy requirements; (b) not exceed, on a weighted average cost, the combined average cost reflected in the IOUs' retail rates, as of January 2001; (c) utilize the less costly of the proposed energy supplies for similar energy products; (d) give special consideration to renewable energy supplies; and (3) give priority to contracts which support timely completion of new generation capacity to improve California's electric capacity reserves.

<u>Procurement Activities and the Negotiating Environment</u>

In seeking to construct a portfolio of long-term contracts to respond to the crisis, the Department faced a difficult set of obstacles that impeded its ability to achieve its goals in each instance. The Department believes, however, that in an overall evaluation of the portfolio its goals were met. The difficulties in negotiation arose from high price levels in both the short-term and long-term markets, seller uncertainty regarding the Department's creditworthiness, unprecedented levels of generation which was not operational (resulting in extremely low reserves), uncertainty about the Department's ability to purchase gas, a drought in the Pacific Northwest and a lack of action by FERC to set meaningful price caps or price level mitigation. Projections for the summer of 2001 predicted numerous blackouts, and the portfolio needed to address that short-term critical need. In addition, the need for additional supplies was projected to decline in 2004, so the Department was initially focused on contracts of 3 years or less. These market limitations reduced the number of sellers willing to contract with the Department and affected the terms of the contracts with those who were willing.

The Department conducted two competitive bidding processes, as described in the record. Based on the responses, the Department determined it was necessary to make tradeoffs as it evaluated each contract. For example, the targeted price of $0.07/kWh typically was not offered for periods of three years or less. The Department regularly reviewed the total estimated energy commitment associated with the contracts that were executed and pending to assess the effect of the cumulative energy and price that would be under contract if all the pending transactions were completed.

[54] Data was initially received from CAISO and the CED, and the Department consulted with the Commission regarding the estimates.

Most of the Department's efforts to enter new contracts ended in July 2001. In May 2001, approximately 50 percent of the on-peak hours of estimated net short energy was under contract, reducing the quantity of spot market energy purchases to within the Department's targeted goal. Short-term energy prices fell precipitously in early June 2001, confirming the Department's expectation. The value of the Department's strategy has been further validated by the continued drop in short-term energy prices.

Sale of Surplus Power

Given the uncertainties regarding the projections of need for energy supplies, the Department from time to time sells excess energy. Such circumstances can occur when load is much lower than expected due to temporary changes, or when direct access is higher than was expected when contracts were entered into, resulting in an overall lower level of energy requirements in all hours. Off-system sales have been much higher than planned due initially to over-scheduling by the IOUs and subsequent higher-than-planned direct access loads now served by other power suppliers. The Department's off-system sales are approximately 5 percent of total load.

The success achieved in reducing prices in the short-term market results in reduced revenues for the Department's sales of surplus power. The Department concurs with the Commission's assessment in this matter:

> [Section 80116] merely provides that DWR may sell surplus power and limits the maximum amount it may charge for that power. However, it does not prevent DWR from recovering losses associated with such sales from end-use customers. Furthermore, it is unlikely that the Legislature expected DWR to purchase the exact amount of power required at all times. Since electricity cannot be stored, DWR would necessarily sell any surplus. Indeed, such action would serve to minimize the losses that would be incurred from surplus energy. Consequently, it is not unreasonable to assume that such losses from sale of surplus power should be included in DWR's revenue requirement.

CPUC Decision 02-03-062 (Order Modifying Decision 02-02-052 and Decision 02-03 – 003 and denying rehearing of these decisions, as modified (March 21, 2002).)

Under AB1X, the costs of the program must be recovered in the Department's revenue requirement. Losses attributable to sales of surplus power are reasonably included in the revenue requirement for the same reasons stated above under the discussion of the long-term contracts. In that context, the costs are just and reasonable.

Renegotiation Efforts

The Department in evaluating the long-term contracts in the context of the current market conditions found that renegotiating some of the prices and terms of the contracts could be beneficial. Accordingly, in the spring of 2002, the Department analyzed which of the contracts merited such renegotiation efforts and approached many of the power suppliers to attempt a renegotiation of the contracts. Understandably, the power suppliers with contracts advantageous to them were often reluctant to engage in a renegotiation of that contract. Several contractors did enter into talks with the Department, and in many cases the contracts were renegotiated with terms and prices more favorable to the Department. Renegotiation efforts are ongoing.

Criticisms of the Long-Term Power Purchase Contracts

Pursuant to AB1X, the State Bureau of Audits conducted an audit of the power purchase program. This audit analyzed the long-term contracts and concluded that in many instances the Department had not obtained optimal terms and prices for those contracts. The audit and the Department's response are included in the record. Director Tom Hannigan's response stated:

> It is inevitable, given the benefit of hindsight and additional information, that DWR would want to revisit and revise certain decisions. However, as a matter of both fairness and accuracy, I believe that the Bureau's report fails in its primary purpose. The Report does not assess the success of DWR's decisions in stabilizing prices and restoring system reliability, nor does it evaluate the reasonableness of DWR's decisions within the context of the crisis environment that they were made, the information that was available to DWR at the time, and against the tremendous risks to the State's economy, and health and safety of its citizens in failing to take decisive action.

The Department obviously did not concur in the Bureau's report, and any notion that the Department is subject to estoppel in any respect by the Bureau's report is equally obviously incorrect.

In addition, criticisms of the long-term contracts were aired in a complaint filed with the Federal Energy Regulatory Commission by the Electricity Oversight Board and the California Public Utilities Commission. This complaint alleges that under Section 206 of the Federal Power Act, the long-term contracts are not just and reasonable due to the market power that suppliers exercised at the time the Department was placed in the position of obtaining contracts to assure reliability and to reduce the cost of energy. This contention is not inconsistent with the Department's determination that the revenue requirement is just and reasonable. Entering into the long-term contracts was a just and reasonable action compared to the alternative of continuing to purchase large volumes of energy at excessive prices in the spot market. The dramatic reduction in spot market prices, and the reduction in total costs, inclusive of the costs of the contracts themselves, as compared to (a) prices that were experienced prior to action by the Department and (b) prices and energy shortages projected by other knowledgeable persons and organizations in the market absent actions by the Department, are evidence that the actions by the Department were appropriate. In the context of AB1X and the emergency conditions then in existence, the actions taken by the Department were reasonable. To maintain a reliable power supply, achieve lower prices in the market and halt the unsupportable continued drain on the State General Fund, the Department reasonably determined to move expeditiously to convert spot market purchases in an explosive market into longer-term bilateral contracts.

The allegations in the Section 206 complaint relate to the just and reasonableness of contracts pursuant to the Federal Power Act and FERC rules, regulations and orders. The just and reasonable determination by the Department must be made in the legal framework set forth in AB1X, as explained above.[55] For this reason and for the reason that the Department is a separate agency from those filing the complaint at FERC, the Department is not subject to estoppel in any respect as a result of that complaint.[56]

Short-Term Energy Purchases

The unstable market conditions and emergency circumstances of the crisis had the most significant impact on the Department's efforts to meet the residual net short energy needs of the three IOUs. Astronomical prices, shortages, and doubt about the Department as a new market player with unproven creditworthiness reduced the Department's negotiating powers in the early days and weeks of the program. Furthermore, given the dysfunctional state of the California energy market during the crisis, there were insufficient suppliers who were willing to sell energy to the Department in order for California to meet its energy requirement. Lacking long-term contracts, the Department satisfied California's demand for energy by purchasing the power on the spot market and entering into short-term energy contracts.

Despite the obstacles that faced the Department, the Department's management maintained a goal of establishing reliability at a low price, and in fact substantially reduced reliance on short-term purchases. This reduced reliance in turn contributed to

[55] If and to the extent that the FERC proceedings result in refunds, lower prices, or changes in the terms and conditions of the long-term contracts, these modifications will be taken into account in future revenue requirement determinations, squaring any federal determinations of just and reasonable, with the Department's own determination. Recovering all of the Department's wholesale long-term power contract costs in the Department's retail revenue requirements is supported, if not required, by the concepts implicit in the federal "filed rate" doctrine, given the combination of the express goal of AB1X for the Department to secure as much low-cost power as possible under contract, the fact that most, if not all, of the contracts were entered into under the supplier's market-based FERC tariffs and the current FERC position concerning market-based rates.

[56] The IOUs' estoppel argument is without legal or factual basis. The IOUs incorrectly argue that DWR is estopped in this proceeding because of the Commission's and the EOB's section 206 complaints filed with FERC challenging the justness and reasonableness of the wholesale rates in the long-term contracts. To establish a claim for estoppel against the government a litigant must prove the same four elements that make up a cause of action for equitable estoppel against a private party as well as a fifth element that applies only to the government: (1) the party to be estopped must be apprised of the facts; (2) the party must intend that his conduct shall be acted upon, or must so act that the party asserting the estoppel had a right to believe it was so intended; (3) the party asserting estoppel must be ignorant of the true state of facts; (4) the party asserting estoppel must rely upon the conduct to his injury; and (5) the party asserting estoppel must demonstrate that "the injury to his personal interests if the government is not estopped exceeds the injury to the public interest if the government is estopped." *La Canada Flintridge Dev. Corp. v. Dept. of Transportation*, 166 Cal. App. 3d 206, 218 (1985). Moreover, "'neither the doctrine of estoppel nor any other equitable principle may be invoked against a governmental body where it would operate to defeat the effective operation of a policy adopted to protect the public.'" *Western Aggregates, Inc. v. County of Yuba*, 100 Cal. App. 4th 259 (2002), quoting *County of San Diego v. Cal. Water Co.*, 30 Cal. 2d 817, 826 (1947).

Here, the IOUs cannot establish a prima facie case of estoppel because, among other reasons, they have not relied to their detriment on the Commission's and the EOB's complaints filed with FERC. In addition, the IOUs improperly seek to invoke the doctrine of estoppel in order to contravene the public policy and legislative intent of AB1X. See *Jordan v. California Dept. of Motor Vehicles*, 100 Cal. App. 4th 431 (2002) (refusing to apply estoppel against the state where state failed to argue in earlier proceedings that arbitration award was a gift of public funds and arbitration award clearly violated an expression of public policy).

reduced prices in the short-term market. Considering the circumstances under which the purchases were made, techniques and strategies used to obtain lower prices, and the favorable results of the program, the Department determines that the costs associated with short-term energy purchases are just and reasonable.

The factors supporting this conclusion are contained in the record, particularly in the declarations of Raymond D. Hart, Peter S. Garris, and Susan Lee. Department management's directive to traders stressed the two general goals of obtaining a reliable supply of energy at a low cost and maintaining grid reliability. Traders were also given specific price caps which they could not purchase above the price limit without express approval from Department management. Traders used standard industry methods to learn prevailing prices and current offers and used typical market trading skills and techniques to seek competitive purchases. Weekly operational meetings were held to discuss risk management issues and determine optimal purchasing amounts and strategies, including price targets and limits.

These management efforts have resulted in average market spot prices consistently lower than the price cap, and an average short-term forward market price that is within the market index for standard products. Given the dysfunctional state of the California energy market and the numerous challenges that existed at the beginning of the crisis, the Department has achieved its goal of meeting California's energy needs by stabilizing the market.[57]

Administrative Costs

For each fiscal year, the Department has budgeted a specified amount that is needed to pay for the administrative and general costs of administering and implementing the Department's Power Program. These amounts include costs for personnel and distributed overhead, consultants, software systems, and miscellaneous operating expenses. To date, the Department has not spent or appropriated funds beyond what it has budgeted. Furthermore, the State has a strict budgetary process in place where the Department must substantiate the justness and reasonableness of all of its administrative expenditures. Approval from the Department of Finance and the State Legislature is required before administrative and general costs can be included in signed legislation. For these reasons and the reasons described below, these costs are just and reasonable.

Personnel and Distributed Overhead

Approximately 60 of the 120 positions in the Department's power program are held by Department personnel, who perform the day-to-day operations necessary to manage the power program. The Department, with the approval of the Department of Finance, distributes overhead costs such as management and fiscal services to individual programs based on the personnel costs of each program to the total of personnel costs for all programs. It is reasonable to include these amounts in the revenue requirement.

[57] The Department's short-term power purchase costs have also been the subject of FERC proceedings, and the same general principles apply here as are noted above with respect to the Department's long-term contract costs and applicable state and federal law.

Consultants

The use of consultants by the power supply program has been necessary and appropriate for several reasons. First, given the sudden emergency of the energy crisis, there was not enough available staff in State service to meet the operational needs of both the new program and the existing State Water Project. The Department is the only State agency that has personnel experienced in energy operations. Second, given the short-term mandate of the new power supply program, it would have been extremely difficult for the Department to hire and train civil service personnel for a very limited purpose and term. Finally, consultants have the necessary expertise to assist department personnel in managing and operating the power supply program. The consultants have been a valuable resource and have offered valuable support in various areas, such as energy trading, contract negotiations, bi-lateral and ISO settlements, development of revenue requirements, natural gas operations, and litigation and regulatory matters.

Software Systems

In order to utilize the energy purchased from the long-term and short-term contracts to fulfill the IOUs' net short energy requirement, the Department needed to have a software system to schedule and submit energy transactions with the California Independent System Operator. The State Water Project has such a system in place, but since AB 1X required that the power program and the State Water Project operate separately, it was necessary for the Department to invest in another system specifically for the purposes of the power program. In addition, the Department needed to implement energy trading and risk management software so that the Department would be able to manage and analyze the market and credit risks of the long-term energy contracts. These software programs are a critical part of the power program and are therefore just and reasonable.

Miscellaneous Operating Expenses

Operating expenses in this category include office equipment, information technology equipment, rent, and various expenses needed to carry out and facilitate the power program. The Department has utilized State purchasing procedures and processes for these expenses.

Long-Term Financing

Costs for implementing long-term financing are not included as a part of the Department's normal administrative and general costs. These include amounts needed to pay for the Department's bond counsel, financial advisors, and personnel costs from the Department of Finance and the State Treasurer's Office. Legal and financial services are necessary to implement the bond financing, and these costs are just and reasonable.

Financing Costs

Financing costs associated with the Department's power supply program are just and reasonable. These amounts includes costs and reserves related to the $6.2 billion in

State General Fund loans, the $4.3 billion Interim Loan, and approximately $11.8 billion in proposed Power Supply Revenue Bonds.

General Fund Loans

From January 2001 to late June 2001, the only funding available to purchase power came directly from the State's General Fund. Approximately $6.2 million was borrowed by the Department at an interest rate based on the State's Pooled Money Interest Account. Since the $6.2 million was used for the power program, the amounts are just and reasonable.

Interim Loan

A $4.3 billion interim loan was necessary for several reasons: (1) to relieve the State's General Fund of the burden of making further advances of money into the Electric Power Fund, (2) to satisfy the conditions specified in the Department's long-term power contracts, and (3) to prove that the Department was sufficiently creditworthy to purchase energy on the spot market. The interim loan was negotiated with the assistance of the State Treasurer's Office and the terms of the loan were approved by the State Director of Finance and the State Treasurer as required by Water Code Section 80132. Given that an interim loan was necessary and authorized by the appropriate State agencies, the interim loan is just and reasonable.

Long-Term Bond Costs

The Department's proposed Power Supply Revenue Bonds are necessary to repay the General Fund and Interim Loan, and to fund bond and power-related reserves required by the credit rating agencies as a condition of their credit rating. As stated above, the General Fund loan and the Interim Loan are just and reasonable costs. The latter amounts are also just and reasonable because those costs are necessary for the Department to receive an adequate investment grade rating in order for it to sell the proposed bonds.

Conclusion

This review of the revenue requirement for a just and reasonable determination results in a conclusion that the revenue requirement is just and reasonable, in that it comports with the Department's statutory responsibilities, accurately reflects lawfully-incurred costs, does not overcollect, and contains costs that are reasonable given the circumstances under which they were incurred. This conclusion is the same whether the standard set forth in the emergency regulations is applied or whether a "prudent person" standard is applied.

APPENDIX 1 MARKET SIMULATION

Wholesale power costs in the western United States are driven by a multitude of factors. These include weather and related electricity demand, precipitation and related hydropower production, the supply and price of natural gas and coal, the power transfer capability of major interties, the operating cost, outages and retirement of generating plants, and the cost, fuel efficiency, and timing of new generating resource additions. To analyze the fundamental drivers underlying the electricity market, the Department completed computer simulations of market activity throughout the Western Electric Coordination Council ("WECC") region. To complete those simulations, the PROSYM price forecasting and market simulation tool was used.

PROSYM is a widely accepted tool for simulating detailed power market activity and has a large market presence in the industry. According to its vendor, 80 percent of the major utilities in North America and many utilities in Europe, Asia, and Australia license PROSYM. It has been used to provide analytical support and to forecast market prices and revenues in a large number of financing transactions for merchant power plants and has gained strong acceptance in the financial community.

PROSYM is a detailed chronological model that simulates hourly operation of WECC generation and transmission resources. Within its simulation framework, PROSYM dispatches generating resources to match hourly electricity demand and establishes market-clearing prices based upon incremental resources used to serve load. Demand and energy forecasts used by PROSYM are developed and provided by the vendor. Annual updates of these forecasts are provided by the vendor based on data obtained from EIA filings and independent analysis by the vendor. For purposes of this revenue requirement determination, the demand and energy forecasts used were those that have been described earlier.

In its hourly dispatch, PROSYM reflects the primary engineering characteristics and physical constraints encountered in operating generation and transmission resources, on both a system-wide and individual unit basis. Within PROSYM, thermal generating resources are characterized according to a range of capacity output levels. Generation costs are calculated based upon heat rate, fuel cost, and other operating costs, expressed as a function of capacity output. Physical operating limits related to expected maintenance and forced outage, start-up, unit ramping, minimum up and down time, and other related characteristics are reflected in the PROSYM simulation.

Hydroelectric resources are also characterized in PROSYM according to expected output levels, including monthly forecasts of expected energy production. PROSYM schedules run-of-river hydroelectric production based upon the minimum capacity rating of the unit. The dispatch of remaining hydroelectric energy is optimized on a weekly basis by scheduling hydro production in peak demand hours when it provides the most value to the electrical system.

Within the PROSYM framework, regional market-clearing prices are established based upon the incremental bid price of the last generating station needed to serve demand. For most of the existing supply, bid prices are composed primarily of incremental production costs. Hourly energy revenues for each generating unit are established as the product of market-clearing prices and the unit's energy production during the relevant hour. The PROSYM framework mirrors a "single-price" auction, so that each generator located within the same market area receives an identical price for its energy output, regardless of its actual bid price or production cost.

While the only "single-price" market auction that still exists in California is the CAISO imbalance energy market, this pricing mechanism is modeled as a proxy for the average price of the residual net short. In the long term, under a balanced supply and demand market, the average residual net short price should approximate the market-clearing price in an "as-bid" environment. In the near-term, the use of a single-price mechanism for the residual net short produces a conservative assessment of market prices.

Within the PROSYM framework, bid prices are developed for each unit and reflect the minimum clearing price the generator is willing to accept to operate. Market-clearing prices reflect the bid of the last generating resource used to meet the last increment of demand. The clearing price also includes an uplift component reflecting start-up and no-load costs of the marginal unit. Station revenues are based on these market-clearing prices within the market area in which the plant is located or assigned.

Based upon the bid price of the marginal generating station in a given hour, the market-clearing price is calculated using the following general approach (stated in dollars per MWh):

Market-Clearing Price = *Incremental Production Cost* + *Start Cost* + *No-Load Cost* + *Price Markup*

Where:

- Incremental Production Cost is calculated as each station's fuel price multiplied by the incremental heat rate, plus variable operations and maintenance cost;

- Start Cost incorporates fuel costs and other operating costs encountered in starting the generating unit, beyond those reflected in the heat rate and variable operating cost assumptions;

- No-Load Cost reflects the difference between average and incremental fuel costs for generating stations that are dispatched at less than full output; and,

- The Price Markup factor recognizes that market forces may drive bid prices above variable production costs. The Department uses this factor to reflect observed market behavior where wholesale prices often rise above the underlying cost of production, particularly during times when supply/demand margins are tight. Such behavior is common in power markets, and has been particularly present in California markets during the last year.

Price Markups are assigned to individual generators depending upon the underlying fuel efficiency, production cost, and technology type. The specific Price Markups are designed so that bid prices rise above the cost of production as less efficient resources are called upon for power production and as the intersection of supply and demand occurs at higher points on the supply curve. The level of Price Markups is determined through an iterative approach with the goal of benchmarking against recent actual wholesale prices, and against observable prices in the forward market.

Three specific bidding strategies were assigned:

(1) Incremental Cost Bidding: Units assigned incremental bidding strategies incorporate only variable operating costs into their bid prices. This bidding strategy reflects a highly competitive market structure. All base load resources and generators with relatively low production costs are assigned this bidding strategy, which reflects the bulk of available supply resources.

(2) Price Markup Bidding: Units assigned Price Markup bidding strategies submit bids close to variable operating costs during all off-peak hours. During on-peak periods, when electricity demand is higher, these stations seek to markup price in proportion to the level of electricity demand. The price markups also vary by season, and are at higher levels during the summer and winter periods when supply/demand balances are the tightest. Intermediate-type generating resources such as older steam turbine units having relatively high production costs are assigned this bid strategy.

(3) Peak Period Bidding: Units assigned Peak Period bidding strategies also submit close to variable operating costs during off-peak hours. Price markups are assigned to these resources during on-peak hours and seasonally. The markups for resources in this category tend to be higher than those applied under the Price Markup strategy. Resources that are assigned Peak Period bidding strategies tend to have the highest production costs, such as simple-cycle gas turbine generators and internal combustion oil-fired plants. Such resources are called upon to produce power only a small portion of the time each year.

The table below provides an overview of bid strategy assignment used in this study. As shown, bid prices are set for a majority of supply resources based on incremental production costs.

CALIFORNIA AND WECC BID STRATEGY ASSESSMENT (PERCENT OF SUPPLY)

	Incremental	Price Markup	Peak Period Bidding	Total
California	68%	28%	4%	100%
Non-California	80%	14%	6%	100%
Total WECC	75%	20%	5%	100%

FERC Price Mitigation

On June 19, 2001, FERC issued an order on price mitigation throughout the WECC. Under this order, a soft price cap was set for the entire WECC based on the heat rate of the least efficient unit and the average natural gas price during the most recent Stage 1 Emergency ("Stage 1") warning period issued by the CAISO. During a Stage 1 (or higher) warning period, the cap was set equal to the energy cost resulting from the heat rate of the least efficient resource being utilized in the market and the average natural gas price in California, plus a $6.00 per MWh cost for operation and maintenance expenses. A 10 percent risk premium was added for energy sold in California. If a Stage 1 warning or higher was not in effect, the effective cap was calculated as 85 percent of the last Stage 1 cap in effect. Based on this formula, the non-Stage 1 price cap at July 8, 2002, was $91.87 per MWh (before the 10 percent risk premium for California power sales). This value was calculated based on gas prices during the most recent system emergency declaration by the CAISO (July 3, 2001).

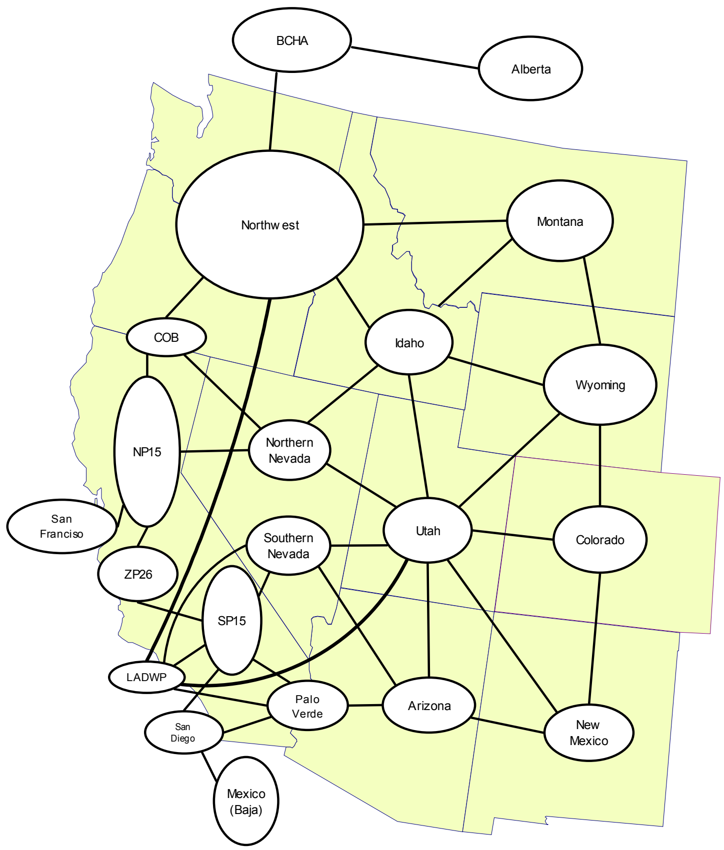
On July 9, 2002, the CAISO declared a Stage 1 emergency and recalculated the price cap at $57.14 per MWh (before the 10 percent risk premium and adjustment for Stage 1 pricing). On July 10, 2002, the CAISO again declared a Stage 1 emergency as well as a Stage 2 emergency and the price cap was recalculated at $55.26 per MWh. The lower price caps calculated on July 9 and 10, 2002, were principally the result of changes in the price of natural gas from July 2001 to July 2002. On July 11, 2002, FERC issued an order replacing the previous formula for calculating the price cap with a hard cap of $91.87 per MWh. FERC took this action as a result of concern that reductions in the price cap during July 2002, as well as future potential variations in the price cap, could cause severe supply disruptions in the western power markets. FERC has ordered that the hard cap of $91.87 per MWh remain in effect from July 12, 2002 through September 30, 2002 (the expiration date of the June 19, 2001, FERC order).

On July 17, 2002, FERC issued an order related to CAISO market design initiatives that established a hard price cap of $250 per MWh, effective October 1, 2002. FERC has indicated it established the price cap at this level to promote further development of new generating resources in California. For purposes of this Determination, the new price cap is assumed to remain in effect from October 1, 2002 through the end of the second revenue requirement period.

WECC Regional Market Definitions

WECC electricity markets sometimes experience binding transmission constraints. Binding transmission constraints occur at times when transmission capacity on a specific linear path is fully utilized and no additional energy can be transported via that line or path. During such times, low-cost generators are forced to reduce output in favor of higher-cost units located within the constrained region.

To reflect transmission constraints encountered in WECC markets, the Department simulated 21 separate market regions, with transfer limitations between each region reflecting expected transmission system configurations. In selecting market regions, the Department examined WECC transmission system operations and also analyzed a number of transmission publications and studies prepared by the WECC.



Separate market-clearing prices were established within each regional market as shown in the figure. In establishing the market-clearing price for each region, the PROSYM simulation takes into account economic import and export possibilities and sets the market-clearing price as the bid price of the marginal generator needed to serve a final increment of demand within the region.

Simulation of New Resource Additions

To meet increases in peak demand, new resource additions must be included in the simulation. A review of potential and planned new resource additions throughout the WECC reveals that they will be built and owned primarily by independent power producers. Generally, the technology, fuel type, size, and location of these new plants will depend primarily upon wholesale power market prices. Prices available to an independent power producer must be sufficient to allow it to earn a return on equity that is consistent with similar risk capital investments.

To forecast the amount of capacity added in each region of the WECC, known potential new generating resources were reviewed to identify those currently under site certification or construction. These plants have a high probability of completion and were added to the simulation resource base in their expected year of completion. Those resources only announced or under feasibility study were added to the simulation resource base only if the annual average market-clearing price in the year of completion is forecast to exceed that which provides a threshold return on equity (these resources are designated for "planning capacity"). Energy revenues (hours of operation multiplied by energy prices) must be greater than the average annual costs (fuel and capacity) of the project. Capacity costs of the particular resource to be added are estimated based on publicly available cost information for the specific type of plant, and on certain financing term, interest rate, and return on equity assumptions.

The table below summarizes these assumptions for combustion turbine and combined cycle combustion turbine plants, which are expected to represent the major portion of all new generating resource additions in the WECC during the Second Revenue Requirement Period.

GENERIC RESOURCE ASSUMPTIONS

Unit Characteristic	Combustion Turbine	Combined Cycle
Heat Rate (Btu/kWh)	11,000	7,100
Fixed O&M ($/kW-year)	3.15	10.50
Variable O&M ($/MWh)	4.20	2.10
Forced Outage Rate (%)	0.00	2.00
Maintenance Outage Rate (%)	4.00	4.00
Financing Term (Years)	15	15
Interest Rate (%)	8.00	8.00
Return on Equity (%)[1]	18.00	18.00

Source: NCI. Cost figures represent 2002 dollars.
[1] After taxes.

To the extent the production simulation model determines that additional generating capacity, beyond that designated as planning capacity, is needed to meet the needs of the region, "generic" new generating units are assumed to be added to the resource mix.

Long-Term Power Contracts

The Department's contract resources were explicitly modeled in the simulation, accounting for their respective capacities, delivery points, minimum takes and other features. These contract resources are assumed to be called upon as a resource for meeting Customer needs and are expected to be dispatched in an economically efficient manner (from the Customers' perspective) as part of a complete resource mix that includes the utility retained generation, the Department's contracts, and residual net short purchases. The Departments Long-Term Power contracts are available for viewing at the Department's web site: http://www.cers.water.ca.gov.

Other Assumptions

A broad array of other inputs and assumptions were made in performing the WECC market simulation. These inputs and assumptions address resource availability, resource retirements, fuel prices, operation and maintenance costs, outage factors, transmission factors, and market conditions, among other factors, which are summarized in the table below.

Category	Assumption
Study Period	January 2001 through December 2003.
Load Forecast	From the EIA-411 filings of the WECC, except for IOU forecasts, which were developed as described elsewhere in this Report.
Load Profiles	SCE and SDG&E load profiles were provided by the IOUs. The PG&E load shape was based on the composite hourly load profile for the 1993-1998 period contained in ProSym, The PG&E load profiles were derived from hourly Edison Electric Institute load data files from the FERC web site.
Existing Resources	From the WECC EIA-411 filings.
Pacific Northwest Hydro	BPA 2000 Pacific Northwest Loads and Resources Study used to calculate monthly capacity and energy values for each hydroelectric station in the region, choosing median conditions from a recorded database of 50 years. Amounts derated during 2002, as described in the Report.
California Hydro	WECC Coordinated Bulk Power Supply report for summer and winter capacity ratings for existing hydro resources. Amounts derated during 2002, as described in the Report.
Resource Retirements	No nuclear retirements at license expiration
Gas Prices	See "Natural Gas Price-Related Assumptions"
O&M Costs	Historical, power plant-specific, non-fuel operation and maintenance ("O&M") costs reported by utilities to FERC, averaged and normalized to develop average starting O&M costs. Amounts allocated between fixed and variable O&M costs. Both fixed and variable O&M costs are assumed to escalate with inflation.
Thermal Resource Models	• Multi-segment incremental heat rate curves. • Fixed and variable O&M costs. • Scheduled outages based on annual maintenance cycles. • Random forced outages based on unit-forced outage rates.
Contracts	• Known firm purchase/sales reported in the WECC Form OE-411 filing. • Transactions are reflected in the load requirements of the buying and selling utilities, in transactions between regions, and by adjusting the transmission capacity. • Transmission capacity between zones required for these transactions is assumed to have priority. Any remaining transmission capacity is used to facilitate additional power transactions between regions, based on economic dispatch and delivery over the remaining transmission capacity.
Thermal Resource Commitment and Dispatch	Unit commitment order determined by marginal operating cost (fuel and variable O&M costs). Commitment determined to satisfy load plus spinning reserve.
Transmission Model	Transmission system and constraints represented using transport model across regions.
Market Structure	Assumed open market across all the regions (region-wide dispatch). Energy interchange between regions occurs when spot price differentials exceed transmission tariff costs.

APPENDIX 2 SUMMARY OF THE MATERIAL TERMS OF THE PROPOSED FINANCING

The following information has been excerpted from the Summary of Material Terms of Financing Documents relating to the Rate Agreement between the Department and the Commission.

Maximum Amount of Bonds Authorized

The Department will issue no more Bonds than it determines are necessary to repay advances from the General Fund and the Interim Loan, to fund the reserves and accounts as described below and to pay costs of issuance using all Bond proceeds and all Department Electric Power Fund balances available at the time of issuance of the Bonds; provided, however, the maximum aggregate principal amount of Bonds which will be issued will not exceed $11.8 billion.

Maturity of Bonds

The Bonds will be issued pursuant to a plan of finance which provides that the final maturity of the series of Bonds with the longest maturity will be no earlier than 19 years from the date of issuance of the first series of Bonds and no later than 21 years from the date of issuance of the first series of Bonds. Such plan of finance will provide that debt service payable on the Bonds will be substantially level, with principal payments commencing no later than 2004. Individual series of bonds issued pursuant to such plan of finance, or individual Bonds of any series, may mature prior to such final maturity date and have different amortization schedules. These maturity dates and amortization requirements do not apply to credit and liquidity facilities, interest rate swap agreements and similar arrangements ancillary to the Bonds.

Flow of Funds

The Indenture will provide for the establishment of the following primary accounts within the Electric Power Fund:

- Operating Account
- Priority Contract Account
- Bond Charge Collection Account
- Bond Charge Payment Account
- Debt Service Reserve Account
- Operating Reserve Account
- Administrative Cost Account

Power Charge revenues and Bond Charge revenues will be applied in the manner summarized below. Such revenues will be applied in the order of priority listed.[58]

Power Charge Revenues. Power charge revenues result from charges imposed by the PUC upon Retail End Use Customers for electric power deemed sold to Retail End Use Customers by the Department, except that Power Charges exclude Bond Charges. Power Charge Revenues are initially deposited in the Operating Account.

Bond Charge Revenues. Bond Charge Revenues result from charges imposed by the PUC upon customers in each of the IOUs' service areas based on the aggregate amount of electric power sold to that customer by an Electrical Corporation and the Department. Bond charges shall be imposed upon customers at all times whether or not the Department is selling Power to such customers, until such time as the Department has recovered the portion of the Department's revenue requirements for Bond Related Costs. Bond Charge Revenues are deposited in the Bond Charge Collection Account.

Operating Account

Amounts held in the Operating Account will be applied as follows:

1. Transfer to Priority Contract Account, by the fifth business day of each month, an amount such that balance held in that account is at least equal to the Priority Long Term Power Contract costs anticipated for the balance of the month and the first five business days of the next following month. If necessary, additional amounts will be transferred to Priority Contract Account as necessary to pay Priority Long Term Power Contract costs.

2. Pay operating expenses, except those described in another paragraph.

3. Pay scheduled principal and interest on the Interim Loan, if and to the extent it remains outstanding.

4. Transfer to Bond Charge Collection Account to extent necessary to reimburse that Account for previous transfers from the Bond Charge Collection Account to (1) Priority Contract Account for payment of Priority Long Term Power Contract costs or (2) Operating Account for payment of Interim Loan.

5a. Transfer to Bond Charge Payment Account, if there are insufficient moneys in the Bond Charge Payment Account to pay debt service.

5b. Pay certain Department obligations to be secured on a parity with Bonds such as amounts due to credit or liquidity facility providers or providers of interest rate swaps (hereinafter referred to as "Parity Obligations"), if not paid from Bond Charge Payment Account.

[58] Where different uses are described with the same number followed by a letter, this indicates that revenues will be applied to such different uses on a parity basis.

5c. Pay bond trustee and other fiduciary costs, if not paid from Bond Charge Payment Account.

6a. Replenish Debt Service Reserve Account, if required as result of the use of Bond Charge revenues for Priority Long Term Power Contract costs or Interim Loan, or a change in investment value.

6b. Fund and replenish reserves, if any, established for Parity Obligations.

7. Reimburse and pay interest on post-11/15/01 advances, if any, from General Fund if and to the extent they remain outstanding.

8. Reimburse and pay interest, in accordance with a schedule to be approved by the Commission, on pre-11/15/01 advances from General Fund if and to the extent they remain outstanding.

9. Replenish Operating Reserve Account to its requirement.

10. Pay subordinated Department obligations such as certain amounts owed to interest rate swap counterparties in certain circumstances (hereinafter referred to as “Subordinated Obligations”) and related reserves if not paid from Bond Charge Payment Account, and subordinated indebtedness and related reserves, if any.

11. Pay other costs incurred by the Department under the Act.

Priority Contract Account

The Priority Contract Account is to provide solely for the payment of amounts due under Priority Long Term Power Contracts. Amounts are transferred to the Priority Contract Account from the Operating Account and from the Operating Reserve Account.

Bond Charge Collection Account

Bond Charge Revenues are initially deposited in the Bond Charge Collection Account. Amounts in the Bond Charge Collection Account will be applied as follows:

1. Transfer to Priority Contract Account for Priority Long Term Power Contract costs, if not paid from Priority Contract Account, Operating Account or Operating Reserve Account.

2. Transfer to Operating Account for Interim Loan, if not paid from Operating Account or Operating Reserve Account.

3a. Transfer to Bond Charge Payment Account for monthly deposits to provide for Bond debt service three months prior to the date such debt service is due.

3b. Transfer to Bond Charge Payment Account for specified costs incidental to payment and security of Bonds (including credit and liquidity facility costs).

3c. Transfer to Bond Charge Payment Account for trustee and other fiduciary costs.

3d. After Department is no longer selling Power, pay Servicing Agreement costs, administrative costs, and certain other costs incurred by the Department under the Act.

4a. Replenish Debt Service Reserve Account, if not replenished from Operating Account.

4b. Fund and replenish reserves, if any, for Parity Obligations.

5. After Department is no longer selling Power, pay certain costs specified in Rate Agreement that previously had been paid from Power Charge revenues.

Bond Charge Payment Account

Funds are transferred from the Bond Charge Collection Account no later than the last business day of each calendar month, sufficient to maintain a balance for the following purposes:

1. Debt Service accrued and unpaid to accrue through the end of the third next succeeding calendar month.

2. Amounts accrued and unpaid for the next 3 months, for agreements with issuers of credit and liquidity facilities entered into in connection with the Bonds.

3. Amounts accrued and unpaid for the next 3 months, for the cost to the Department of Fiduciaries associated with the issuance and administration of the Bonds.

4. Amounts accrued and unpaid for the next 3 months, for the Department's Bond charge servicing costs.

5. The redemption Price of any bonds called for redemption, other than for sinking fund requirements.

6. The Trustee to pay interest and principal, and redemption amounts from this account.

7. Trustee to pay Parity Obligations and to other persons as specified.

Debt Service Reserve Account

The Department will pay into the Debt Service Reserve Account an amount to equal the debt service reserve requirement, from Bond proceeds or other available funds

1. Moneys in account used to satisfy any deficiency that arises in the Bond Charge Payment Account.

2. Debt Service Reserve Account to be replenished from Power Charge revenues if a deficiency therein results from use of Bond Charge revenues for Priority Long Term Power Contract costs or Interim Loan, or from change in investment value, and from Bond Charges in other cases or if sufficient Power Charge revenues are not available for such purpose.

Operating Reserve Account

Whenever bonds are issued, the Department shall pay into the Operating Reserve Account from the proceeds or from other funds, the amount required to equal the Operating Reserve Account Requirement.

1. Moneys in Operating Reserve Account will be used to satisfy any deficiency that arises in Operating Account. Such moneys to be applied in order of priority and for the purposes specified in 1 through 6 under Power Charge Revenues above. A portion of the Operating Reserve Account (the "Priority Contract Contingency Reserve Amount") will be reserved solely for the payment of Priority Long Term Power Contract costs as described below, as the last money in the Operating Reserve Account to be spent.

2. The Operating Reserve Account is to be replenished from Power Charge revenues, after reimbursement, in accordance with a schedule approved by the Commission, of amounts advanced from the General Fund if not previously repaid.

Administrative Cost Account

Funds are received from the Operating Account or, if the Department is no longer selling power, the Bond Charge Collection and Payment Accounts, the funds necessary to pay administrative costs.

All Administrative costs of the Department incurred in administering Division 27 of the Water Code shall be paid from this account.

Sizing or Methodology for Sizing Reserves, Fund Balances and Debt Service Coverage; Initial Deposits

Reserves, Fund Balances and Coverage

(1) **Debt Service Reserve Account:** A Debt Service Reserve Account requirement will be established in an amount equal to 50 percent of maximum aggregate annual debt service, determined based on

combination of known debt service in the case of fixed rate bonds and assumed rates in the case of variable rate bonds. The size of such Debt Service Reserve Account requirement may be increased to an amount not greater than 100 percent of maximum aggregate annual debt service by the Department only if the Department has determined that such increase will not increase the Department's projected net debt service on the Bonds by more than 3.5 percent as compared to the Department's projected net debt service that would have otherwise been payable if the Debt Service Reserve Account requirement were established at 50 percent of maximum aggregate annual debt service, taking into account all dependent variables, including the respective ratings of the Bonds.

(2) **Operating Reserve Account:** An Operating Reserve Account requirement will be calculated by the Department prior to the issuance of the first series of Bonds and at the beginning of each revenue requirement period including the Priority Contract Contingency Reserve Amount referred to below. Such requirement is to be equal to the largest aggregate difference between the Department's projected operating expenses and the Department's projected Power Charge revenues during any consecutive seven month period starting during the then current revenue requirement period, taking into account a range of possible future outcomes, but may be increased to an amount not to exceed $1.2 billion at the time of issuance of the Bonds. The Priority Contract Contingency Reserve Amount is to be the maximum amount projected to be payable on Priority Long Term Power Contracts in any month during the then current revenue requirement period.

(3) **Operating Account:** The Department will covenant to include in its revenue requirements amounts sufficient to cause a "Minimum Operating Expense Available Balance" to be on deposit in the Operating Account by the first business day of each month. The Minimum Operating Expense Available Balance is to be calculated by the Department at the time of each determination of a revenue requirement and will be an amount equal to the largest projected difference between the Department's projected operating expenses and the Department's projected Power Charge revenues during any one month period during the then current revenue requirement period, taking into account a range of possible future outcomes.

(4) **Coverage:** To provide for coverage of Bond Related Costs, the Department will be required to set aside in the Bond Charge Payment Account, three months prior to its payment date, an amount equal to estimated Bond Related Costs, based on assumptions and projections as appropriate, and to determine the Department's revenue requirements submitted to the Commission so that the amount in the Bond Charge Collection Account from time to time is equal to one month's estimated Bond Related Costs, based on assumptions and projections as appropriate. Such deposit

requirements may be increased to cover a period of time not in excess of an aggregate of six months.

Initial Deposits

Funds are anticipated to be deposited from Bond proceeds or Department balances, upon the issuance of the initial or subsequent series of Bonds, as summarized below.

(1) To the Bond Charge Collection Account and Bond Charge Payment Account, amounts necessary to initially satisfy the requirements described in “Coverage” above.

(2) To the Bond Charge Payment Account, an amount to fund debt service on Bonds and other Bond Related Costs between the time the Bonds are delivered and the time when the initial Bond Charges are fully in effect and being received in amounts adequate to fund ongoing debt service, only if such amounts are not expected to be available from Power Revenues.

(3) To the Debt Service Reserve Account, an amount equal to the Debt Service Reserve Account requirement referred to above.

(4) To the Operating Account, an amount equal to the Minimum Operating Expense Available Balance referred to above.

(5) To the Operating Reserve Account, an amount equal to the Operating Reserve Account requirement referred to above, including the Priority Contract Contingency Reserve Amount referred to above.

(6) To the Priority Contract Account, an amount equal to the maximum projected monthly amount due on Priority Long-Term Power Contracts during the current revenue requirement period.

Addendum to Summary of Material Terms

The Summary of Material Terms of Financing Documents has been modified by the Addendum to Summary of Material Terms approved by the Commission on August 12, 2002. The text of the Addendum is as follows:

THIS AMENDED AND RESTATED ADDENDUM TO SUMMARY OF MATERIAL TERMS OF FINANCING DOCUMENTS, dated as of August 8, 2002 (the “Addendum”), is a supplement to the Summary of Material Terms of Financing Documents (“Summary of Material Terms”) which was attached to a memorandum dated February 21, 2002 from Department of Water Resources (“DWR”) to the California Public Utilities Commission (“CPUC”) as Attachment A. This Addendum amends and restates the Addendum dated July 17, 2002 previously submitted to the CPUC. After approval by the CPUC on February 21, 2002, a Rate Agreement was executed by the CPUC and DWR on March 8, 2002 (the “2002 Rate Agreement”).

The amendments to the Addendum reflected herein address issues identified during discussions with the rating agencies reviewing the Bonds, including increasing the authorized principal amount of Bonds and making other provisions for an increase to the "Minimum Operating Account Expense Available Balance" in the Operating Account to be established under the Indenture. The Department has determined that these changes will enable the Bonds to receive more favorable credit ratings than would otherwise be available and result in substantially lower overall debt service costs associated with the Bonds (taking into account the present value of costs and benefits of the changes contemplated hereby) and the Department will implement such changes only if the Department determines that such substantially lower overall debt service costs are achieved.

It is anticipated that DWR will enter into a Trust Indenture among DWR, the Treasurer of the State of California as Trustee, and U.S. Bank, N.A., as Co-Trustee (the "Bond Indenture") in connection with its issuance of Power Supply Revenue Bonds, Series 2002. All undefined terms in this Addendum shall be defined by reference to the 2002 Rate Agreement and the Bond Indenture.

1. <u>Maximum Amount of Bonds Authorized.</u>

The maximum aggregate principal amount of Bonds which may be issued may be increased from $11,100,000,000 but may not result in net proceeds of more than $11,950,000,000. Such increase is intended to permit the Department to increase the Minimum Operating Expense Available Balance and the initial deposit to the Operating Account as described below. As used in the paragraph "net proceeds" means the aggregate principal amount of Bonds issued, plus original issue premium, less original issue discount.

2. <u>Bond Indenture.</u>

The Bond Indenture will contain language that reflects the understandings contained in this Addendum. DWR and CPUC will also enter a letter agreement that obligates each party to act in accordance with the applicable provisions of the Bond Indenture relating to the subject matter of this Addendum.

3. <u>Disposition of Operating Reserve Account.</u>

DWR shall separately notify CPUC in writing each time the Operating Reserve Account Requirement is reduced pursuant to the Bond Indenture. Whenever such reduction in the Operating Reserve Account Requirement occurs, any excess amounts in the Operating Reserve Account ("Excess Amounts") will be used at such time to satisfy any deficiencies existing at such time in the payment of Items 1-8 under "Power Charge Revenues" in Section III of the Summary of Material Terms (including repayment in full of the General Fund of the State). Unless otherwise agreed by both the CPUC and DWR, each acting in their own discretion, any Excess Amounts remaining after application to the uses described in the preceding sentence, shall be used, at the direction of CPUC, after consultation with DWR, to (i) adjust DWR Charges or (ii) with the agreement of DWR, reduce debt outstanding under the proposed Bond Indenture, in all instances, upon consideration of the interests of the retail customers of the Electrical Corporations, DWR and, if applicable, ESP retail customers.

4. Disposition of Priority Contract Account.

At the point at which DWR no longer holds any Priority Long Term Power Contracts, any balance in the Priority Contract Account shall be disposed of in the same fashion as Excess Amounts in Section 3 of this Addendum.

5. Disposition of Operating Account.

DWR shall separately notify CPUC in writing when the Minimum Operating Expense Available Balance has been reduced pursuant to the Bond Indenture as a result of the Department no longer purchasing the Residual Net Short. Whenever such reduction in the Minimum Operating Expense Available Balance occurs, any excess amounts in the Operating Account shall be utilized in the same manner as Excess Amounts as set forth in Section 3 of this Addendum.

If and when the DWR is no longer responsible for the payment of costs under any Power Supply Contracts, all excess amounts in the Operating Account shall be utilized in the same fashion as Excess Amounts as set forth in Section 3 of this Addendum to Summary of Material Terms, provided that, the Operating Account may remain open to pay those administrative expenses that would otherwise have to be paid out of Bond Charge Revenues as described in Section III of the Summary of Material Terms. If the Operating Account is held open for the purpose of paying these administrative expenses after DWR is no longer selling power, all amounts not needed to pay such administrative expenses shall be treated as Excess Amounts.

6. Definition of Revenues.

The definition of Revenues under the proposed Bond Indenture shall include any moneys actually received by DWR which have been recovered as compensation or damages from providers of Power or other commodities or services acquired by DWR pursuant to the Enabling Measures. Notwithstanding the foregoing, the definition of Revenues may exclude moneys received if and to the extent DWR's entitlement thereto is not final and is subject to appeal, other review or refund. Nothing in the Bond Indenture will obligate DWR to recover and actually receive money as such compensation or damages from such providers.

7. Application of Power Charge Revenues.

If, at any time, DWR has received "Power Charge Revenues" which are available to pay Items 10 and 11 under Section III of the Summary of Material Terms, any such moneys will be used instead to satisfy any remaining outstanding amounts due under the Interim Loan and to the General Fund of the State until the Interim Loan and the General Fund of the State have been repaid in full. Any usage of these moneys for Items 10 and 11 after repayment of the Interim Loan and the General Fund of the State in full, shall require the consent of the CPUC. However, subordinated payments under

Qualified Swaps and Reimbursement Obligations may be paid without regard to the preceding two sentences.

8. Assumptions in Proposed Bond Indenture.

Wherever the Bond Indenture requires DWR to consult with the Commission with respect to assumptions made by DWR, DWR shall involve the Commission in the development of these assumptions, by conferring regularly, in a manner consistent with DWR's obligations under Article 4 of the 2002 Rate Agreement.

9. Replenishment of Operating Reserve Account and Debt Service Reserve Account.

These accounts will be replenished in the event of a deficiency beginning no later than the seventh month following the determination of a deficiency, in approximately equal or greater amounts so that the deficiency will be cured no later than the twelfth month following a determination of the deficiency. During the existence of any deficiency in either Account, Power Charge Revenues otherwise available to be used for items 10 and 11 under "Power Charge Revenues" in Section III of the Summary of Material Terms shall instead be used to replenish the Operating Reserve Account or the Debt Service Reserve Account, as applicable. However, subordinated payments under Qualified Swaps and Reimbursement Obligations may be paid without regard to the preceding sentence.

10. Minimum Operating Expense Available Balance Revenue Requirement Calculation; Replenishment of Operating Account.

The Department will covenant to include in its revenue requirements amounts sufficient to cause a "Minimum Operating Expense Available Balance" to be on deposit in the Operating Account. The Minimum Operating Expense Available Balance is to be calculated by the Department at the time of each determination of a revenue requirement. "Minimum Operating Expense Available Balance" for so long as the Department continues to purchase the Residual Net Short, may be an amount up to and including $1,000,000,000, and thereafter will be an amount equal to the largest projected difference between the Department's projected operating expenses and the Department's projected Power Charge revenues during any one month period during the then current revenue requirement period, taking into account a range of possible future outcomes.

The Indenture may provide that, if on any date the Operating Account balance falls below specified levels, the Department will submit a new Revenue Requirement to the Commission providing for revenues sufficient to restore the Operating Account to the Minimum Operating Expense Available Balance within periods permitted for restoration to be specified in the Indenture. The last day of any required period for restoration which may be specified in the Indenture shall be no sooner than 225 days following the submission of such Revenue Requirement to the Commission. The time period during which the Commission is required to act in response to any such submission under the Rate Agreement will not be affected by such provision.

11. Operating Reserve Account Requirement Calculation.

The Bond Indenture will provide that the Operating Reserve Account Requirement shall be calculated, in respect of each Revenue Requirement Period, as the greater of (a) the largest aggregate amount projected by DWR by which Operating Expenses exceed Power Charge Revenues during any consecutive seven calendar months commencing in such Revenue Requirement Period and (b) either (i) 18% of DWR's projected annual Operating Expenses for any Revenue Requirement Period in which DWR is procuring all or a portion of the Residual Net Short and which commences prior to 2006, or (ii) 12% of DWR's projected annual Operating Expenses for any Revenue Requirement Period in which DWR is not procuring all or a portion of the Residual Net Short or which commences after 2005; provided, however, that solely for purposes of (b) above, for Revenue Requirement Periods commencing after 2003, the projected amount shall not be less than the applicable percentage of Operating Expenses for the most recent 12 month period for which reasonably full and complete Operating Expense information is available, adjusted in accordance with the Indenture to the extent the Department no longer is financially responsible for any particular Power Supply Contract; and provided further, however, that at the time of the issuance of the Bonds such requirement may be set at an amount not to exceed the amount specified by the Summary of Material Terms. Notwithstanding the foregoing, in connection with the determination of whether additional Bonds under the Bond Indenture may be issued, the relevant calculation under clause (a) above shall made in respect of a consecutive seven (7) calendar month period in a twenty-four (24) month period commencing on the first day of the calendar month next succeeding the date of delivery of the additional Bonds.

12. Fiduciary Expenses.

Fiduciary expenses shall not be paid out of the Debt Service Reserve Account. In the event of a default, fiduciary expenses shall be paid only out of Power Charge Revenues or Bond Charge Revenues.

13. Power Charge Revenues.

Item 6b under Power Charge Revenues in Section III of the Summary of Material Terms shall be deleted.

14. Debt Service Reserve Account.

If, at any time, the amounts in the Debt Service Reserve Account exceed the Debt Service Reserve Requirement, any excess shall be retained in such account or transferred to the Bond Charge Collection Account.

15. Certain Definitions.

The Bond Indenture shall contain definitions of "Operating Expense", "Emergency Measures" and "Enabling Measures" substantially like those contained in Exhibit A to this Addendum. The Bond Indenture shall also specify that costs not otherwise authorized to be incurred by DWR pursuant to the Enabling Measures cannot be incurred alternatively by means of a reduction to Revenues or any other type of credit having a similar effect.

16. Operating Account Initial Deposit.

The initial deposit to the Operating Account may be increased to be an amount such that the minimum daily balance of the Operating Account projected by DWR in the "base case" scenario supporting DWR's 2003 Revenue Requirement Filing, as it may be amended in accordance with the Summary of Material Terms and this Addendum, is $1,000,000,000 from the Closing Date through February 15, 2003, provided, however, that the sum of the initial deposits to the Priority Contract Account and Operating Account shall not exceed in the aggregate $1,800,000,000.

17. Priority Contract Account Initial Deposit.

The initial deposit to the Priority Contract Account shall be the amount estimated by DWR that would have been required to be on deposit in the Priority Contract Account on the Closing Date, if the requirements of the Bond Indenture had already been in effect on an ongoing basis.

18. Amortization of Bonds.

Debt service on the Bonds will be considered to be substantially level so long as the projected aggregate debt service on the Bonds payable in any year following the first year in which principal on the Bonds is due is not more than five percent (5%) higher than any other year following the first year in which principal on the Bonds is due.

APPENDIX 3 REFERENCE INDEX OF MATERIALS UPON WHICH DEPARTMENT RELIED TO MAKE DETERMINATIONS

Quasi-Legislative Record of Revenue Requirement Reasonableness Determination

Renegotiated Power Contracts

- Calpeak Power LLC Agreements
  - Border
  - El Cajon
  - Enterprise
  - Midway
  - Panoche
  - Vaca-Dixon
  - Mission Termination Contract
  - Settlement Agreement

- CalPine Energy Services, L.P.
  - CalPine 1
  - CalPine 2
  - CalPine 3
  - CalPine 4
  - Settlement Agreement

- Constellation Power Source, Inc./High Desert Power Project, LLC
  - Constellation
  - High Desert
  - Settlement Agreement

- Whitewater Energy Corporation
  - Whitewater Hill
  - Cabazon

Federal Energy Regulatory Commission Orders

- Order Directing Remedies for California Wholesale Electric Markets in Dockets Nos. EL00-95-000 and related cases (December 15, 2000)
- Order Granting Motion Concerning Creditworthiness Requirement and Rejecting Amendment No. 40 in Docket Nos. ER 01-3013-000 and ER 01-899-008 (November 7, 2001)

California Public Utilities Commission Decisions and Agreements

- Rate Agreement By and Between the State of California Department of Water Resources and State of California Public Utilities Commission (March 8, 2002)

- Rate Agreement between the CPUC and DWR (CPUC Proceedings A.00-11-038, A.00-11-056, A.00-10-028)
- Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development (CPUC Proceeding R.01-10-024)

Declarations of Peter S. Garris, Raymond D. Hart, and Ronald O. Nichols in Opposition to Motion for Issuance of Writ of Mandate in *Pacific Gas and Electric Company v. California Department of Water Resources and Thomas M. Hannigan*

PROSYM Model

On July 10, 2002 the Department provided a Notice of Additional Significant Material (Proposed Determination of Revenue Requirement). Following is an index of the material relied upon and provided:

SUPPLEMENTAL INDEX OF QUASI-LEGISLATIVE RECORD OF CALIFORNIA DEPARTMENT OF WATER RESOURCES REVENUE REQUIRMENT REASONABLENESS DETERMINATION

Document #	Subject	Total Pages
1	October 19, 2001--Agreement – BPA Exchange Modification PPA	3
2	November 12, 2001—News Release on Energy Costs—Significant downward trend in States energy costs continues in September and October. Hundreds of millions of dollars saved every month since May	1
3	November 28, 2001 –News Release on Spot Market Data—DWR today released spot market data for July and August	2
4	December 7, 2001—News Release on Second Quarter Energy Report--Governor Davis announces the signing of two long-term renewable energy contracts	2
5	December 10, 2001—News Release on DWR activities and expenditures report for second quarter, 2001	2
6	December 10, 2001—News Release on Response to State Auditor—DWR releases response to State Auditor's report on Department's power purchase program	19
7	December 19, 2001—News Release on Spot Market Data—DWR today released spot market data for September and October, 2001.	1
8	February 5, 2002—News Release on Energy Costs – January 2002 energy costs fall to all-time low for DWR	2
9	February 15, 2002—News Release on Energy Purchases/Sales—Spot Market Data for November and December, 2001 released today	2

Document #	**Subject**	**Total Pages**
10	February 21, 2002—Opinion Adopting a Rate Agreement Between the Commission and the California Department of Water Resources	122
11	February 21, 2002—Letter to the California Public Utilities Commission Modifying November 5, 2001 Revenue Requirement Filing	13
12	February 21, 2002—Order Accepting November 5, 2001 Revenue Requirement	149
13	February 25, 2002—News Release on DWR Power Fund—Electric Power Fund Financial Statements, January 29, 2001-June 30, 2001	22
14	March 12, 2002--Amended Capitol PPA – Renegotiated	17
15	March 12, 2002—News Release on Energy Costs—February 2002 energy costs lowest monthly total to date	3
16	March 21, 2002—Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assemble Bill 1X and Decision	59
17	March 27, 2002—News Release on Power Fund—DWR Electric Power Fund—Financial Statements, July 1, 2001 through February 28, 2002	5
18	April 15, 2002—News Release on Energy Costs—DWR releases Spot Market Data for January and February 2002. Updates power costs through March	1
19	April 19, 2002—Southern California Edison Company Governor's 20/20 Rebate Program Data Requests	15
20	April 22, 2002--Amended and Restated PPA – Constellation – w/Legal Opinion Letter	21
21	April 22, 2002--Amended & Restated Calpine Agreement – Renegotiated	77
22	April 22, 2002—News Release of Renegotiated Long-Term Power Contracts	5
23	April 24, 2002—Letter to CPUC regarding possible 20/20 program	3
24	April 24, 2002—Letter to CPUC from SDG&E regarding their response to energy division data request on 200/2 20/20 Program	3
25	April 25, 2002--Amended and Restated PPA – Whitewater Hill – Renegotiated	12
26	April 25, 2002--Amended & Restated Agreement – Whitewater Cabazon Project – Renegotiated	21

Document #	Subject	Total Pages
27	April 25, 2002--FERC Order Setting Complaints for Hearing Establishing Hearing Procedures and Consolidating Proceedings – Docket EL02-60-000, EL02-62-00) – CPUC/EOB Market Manipulation Complaints	28
28	April 29, 2002—Letter to CPUC regarding the Second 20/20 Data Request	7
29	May 2, 2002--Amended and Restated PPA & Dispatch Agreement – CalPeak Vaca Dixon	58
30	May 2, 2002--Amended and Restated PPA & Dispatch Agreement – CalPeak Panoche	58
31	May 2, 2002--Amended and Restated PPA & Dispatch Agreement – CalPeak Midway	60
32	May 2, 2002--Amended and Restated PPA & Dispatch Agreement – CalPeak Enterprise	58
33	May 2, 2002--Amended and Restated PPA & Dispatch Agreement – CalPeak El Cajon	60
34	May 2, 2002--Amended and Restated PPA & Dispatch Agreement – CalPeak Border	58
35	May 2, 2002--Termination Agreement—CalPeak Mission	7
36	May 2, 2002--Agreement – CalPeak Settlement Agreement	16
37	May 2, 2002—News Release on Renegotiated CalPeak Power Contract—DWR successfully restructures CalPeak contract	2
38	May 17, 2002—Demand Reserves Purchase Agreement	30
39	May 23, 2002—Letter to CPUC regarding Governor Davis issuing Executive Order D-56-2, which requires the Department of Water Resources to implement a limited-term rate reward program	5
40	May 24, 2002—Letter from CPUC to All Parties regarding the Draft Resolution E-3770 of the Energy Division	12
41	June 4, 2002—Presentation on Analysis of Resource Needs (Years 2003-2010) by the Electric Power Group	18
42	June 6, 2002—Testimony of James McMahon on behalf of the California Department of Water Resources Rulemaking 02-01-011 Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060	37
43	June 6, 2002—20/20 Resolution E-3770 by Executive Order	22
44	June 6, 2002—Testimony of Craig McDonald on behalf of the California Department of Water Resources Rulemaking 02-01-011 Implementation of Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060	44

Document #	Subject	Total Pages
45	June 14, 2002—News Release on Revenue Requirement—The proposed determination of the 2003 revenue requirement has been submitted to the CPUC	59
46	June 17, 2002—News Release on Energy Costs—DWR releases Spot Market Data for March and April 2002. Updates power costs through May	1
47	July 1, 2002—CPUC Monthly Reporting of Cost and Revenue Summary – Monthly and Cumulative 11/01-5/02-Reports Generated Internally	69
48	July 8, 2002—Documentation of 2003 IOU Load and Sales Forecast	5
49	No Date—2002 Financial Impact of CPA Demand Reserve Program	2
50	No Date—Forecast for Distributed Generation in California	17
51	No Date—20/20 Rebate Program Analysis	13
52	July 9, 2002—Prepared Testimony of Douglas Montague on behalf of the CDWR in Application 00-11-038 et. Al.—Bond Charge Phase of the Rate Stabilization Proceeding	18

On July 26, 2002 the Department provided a Notice of Additional Significant Material (Proposed Determination of Revenue Requirement). The included material consisted of:

The transcript of the interim loan obtained by the Department on June 26, 2001.

A CD containing a detailed computer model used prior to June 2001 in evaluating alternative combinations of long-term contract proposals. This model was a precusor tool to the PROSYM model.

On August 9, 2002 the Department provided a Notice of Additional Significant Material (Proposed Determination of Revenue Requirement). This consisted of:

Updated Financial Model

ProSym output

Just and Reasonable Declarations for Pete Garris, Jim Olson, Ron Nichols, Douglas Montague, and Susan Lee

Information Supporting the Just and Reasonable Declarations of Pete Garris and Ron Nichols

Summary of Changes

On August 13, 2002 the Department provided a Notice of Additional Significant Material (Proposed Determination of Revenue Requirement). This consisted of:

Updated Bond Charge Testimony

Comments received from Donald E Brookhyser, Counsel for EPUC, Goodrich and Kimberly Clark

Comments received from Al Colley, an individual

Comments received from the California Large Energy Consumers Association

Comments received from San Diego Gas and Electric Company

Comments received from Southern California Edison Company

Comments received from Pacific Gas and Electric Company